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, 2019

OR

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

For the transition period from ________________ to ___________________

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

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	WEC	New York Stock Exchange

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

None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes ☒ No ☐

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

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

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

Indicate by check mark whether the Registrant 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 $26.3 billion based upon the reported closing price of such securities as of June 30, 2019.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2020):

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 6, 2020, are incorporated by reference into Part III hereof.

WEC ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2019
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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
Bostco	Bostco LLC
Coyote Ridge	Coyote Ridge Wind, LLC
Integrys	Integrys Holding, Inc.
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
Thunderhead	Thunderhead Wind Energy LLC
UMERC	Upper Michigan Energy Resources Corporation
Upstream	Upstream Wind Energy LLC
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WECC	Wisconsin Energy Capital Corporation
WECI	WEC Infrastructure LLC
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

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

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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
SAB	Staff Accounting Bulletin

Environmental Terms

ACE	Affordable Clean Energy
Act 141	2005 Wisconsin Act 141
BATW	Bottom Ash Transport Water
BSER	Best System of Emission Reduction
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
NAAQS	National Ambient Air Quality Standards
GMZ	Groundwater Management Zone
MATS	Mercury and Air Toxics Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
PCB	Polychlorinated Biphenyl
RTR	Risk and Technology Review
SO_2	Sulfur Dioxide
VN	Violation Notice

Measurements

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
AG	Attorney General
AMI	Advanced Metering Infrastructure
ARR	Auction Revenue Right
Badger Hollow I	Badger Hollow Solar Farm I
Badger Hollow II	Badger Hollow Solar Farm II
CFR	Code of Federal Regulations
Compensation Committee	Compensation Committee of the Board of Directors
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
ERP	Enterprise Resource Planning
Exchange Act	Securities Exchange Act of 1934, as amended
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism

GUIC	Gas Utility Infrastructure Costs
Holding Company Act	Wisconsin Utility Holding Company Act
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 6	Oak Creek Power Plant Unit 6
OC 7	Oak Creek Power Plant Unit 7
OC 8	Oak Creek Power Plant Unit 8
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
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)
ROE	Return on Equity
RTO	Regional Transmission Organization
SMP	Natural Gas System Modernization Program
SOX	Section 404 of the Sarbanes-Oxley Act
SREC	Solar Renewable Energy Certificate
SSR	System Support Resource
Tax Legislation	Tax Cuts and Jobs Act of 2017
Tilden	Tilden Mining Company
Two Creeks	Two Creeks Solar Project
VAPP	Valley Power Plant
VITA	Variable Income Tax Adjustment Rider

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 and 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, environmental matters, 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, 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 developments, unusual weather, 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 recent and future federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, 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 the Tax Legislation as well as those that affect our ability to use production tax credits and investment tax credits;

- 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;

- Factors affecting the implementation of our generation reshaping plan, including related regulatory decisions, the cost of materials, supplies, and labor, and the feasibility of competing projects;

- 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 changing commodity prices, particularly natural gas and electricity, and the availability of sources of fossil fuel, natural gas, 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;

- The risk associated with the values of goodwill and other intangible assets 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 ability to maintain effective internal controls in accordance with SOX, while both integrating and continuing to consolidate our enterprise systems;

- 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.

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 Bishop Hill III, Coyote Ridge, Upstream, WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, 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 21, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

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 regulated natural gas and electricity, 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, 2019, we had six reportable segments, which are discussed below. For additional information about our reportable segments, see Note 21, 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.

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.

- 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

The following table shows electric utility operating revenues, including steam operations, for our Wisconsin segment disaggregated by customer class for the year ended December 31, 2017. For information about our operating revenues disaggregated by customer class for the years ended December 31, 2019 and 2018, see Note 4, Operating Revenues.

(in millions)	2017
Operating revenues	
Residential	$ 1,581.5
Small commercial and industrial (1)	1,400.9
Large commercial and industrial (1)	913.7
Other	30.5
Retail (1)	3,926.6
Wholesale	233.4
Resale	270.6
Steam	23.3
Other operating revenues (2)	105.1
Total operating revenues (1)	$ 4,559.0

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

(2) Includes SSR revenues, amounts collected from (refunded to) customers for certain fuel and purchased power costs that exceed a 2% price variance from costs included in rates, and other revenues, partially offset by revenues from Tilden that were addressed in WE's December 2019 Wisconsin rate order.

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 2019, retail revenues accounted for 90.4% of total electric operating revenues, wholesale revenues accounted for 4.4% of total electric operating revenues, and resale revenues accounted for 3.8% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Operating Income 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 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 a decline in weather-normalized retail electric sales in 2019 due primarily to reduced industrial sales. We currently forecast retail electric sales volumes, excluding the Tilden mine located in the Upper Peninsula of Michigan, to grow between 1% and 1.5% over the next five years, assuming normal weather. Electric peak demand is expected to grow between flat and 0.5% over the next five years.

Customers

	Year Ended December 31		
(in thousands)	2019	2018	2017
Electric customers – end of year			
Residential	**1,449.7**	1,441.3	1,431.4
Small commercial and industrial	**174.6**	173.2	172.2
Large commercial and industrial	**0.9**	0.9	0.9
Wholesale and other	**2.7**	2.7	2.6
Total electric customers – end of year	**1,627.9**	1,618.1	1,607.1
Steam customers – end of year	**0.4**	0.4	0.4

Electric Commercial and Industrial Retail Customers

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

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 power purchase agreements, including the Point Beach power purchase agreement 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 2020:

	Estimate (1)	Actual		
	2020	2019	2018	2017
Company-owned generation units:				
Coal	32.5%	**36.3%**	44.7%	48.5%
Natural gas:				
Combined cycle	24.3%	**26.8%**	19.7%	16.5%
Steam turbine	0.9%	**0.8%**	0.6%	0.8%
Natural gas/oil peaking units	4.4%	**0.9%**	1.7%	1.1%
Renewables (2)	4.2%	**4.4%**	4.1%	4.1%
Total company-owned generation units	66.3%	**69.2%**	70.8%	71.0%
Power purchase contracts:				
Nuclear	19.0%	**19.8%**	18.6%	17.7%
Natural gas	2.7%	**1.8%**	1.5%	1.3%
Renewables (2)	2.5%	**2.0%**	2.4%	2.9%
Other	1.8%	**1.8%**	1.7%	1.6%
Total power purchase contracts	26.0%	**25.4%**	24.2%	23.5%
Purchased power from MISO	7.7%	**5.4%**	5.0%	5.5%
Total purchased power	33.7%	**30.8%**	29.2%	29.0%
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 February 2020 NYMEX.

(2) Includes hydroelectric, biomass, 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 approximately 7,118 MW of generation capacity, including owned and jointly owned facilities. 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.

On March 31, 2019, we added to our electric generation portfolio when UMERC's new natural gas-fired generation with a 187 MW rated capacity in the Upper Peninsula of Michigan achieved commercial operation. See Note 25, Regulatory Environment, for more information.

Reshaping our Generation Fleet

The planned reshaping of our generation fleet balances reliability and customer cost with environmental stewardship. Taken as a whole, this plan should reduce costs to customers, preserve fuel diversity, and lower carbon emissions. Generation reshaping includes retiring older fossil fuel generation units, building state-of-the-art natural gas generation, and investing in cost-effective zero-carbon generation. In 2019, we met and exceeded our 2030 goal of reducing CO_2 emissions by 40% below 2005 levels and are re-evaluating our longer-term CO_2 reduction goals. We have already retired more than 1,800 MW of coal-fired generation since the beginning of 2018, and expect to continue adding natural gas-fired generating units and renewable generation, including utility-scale solar projects. The generation reshaping plan included the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units as well as the March 2019 retirement of the Presque Isle power plant. For more information related to these power plant retirements, see Note 6, Property, Plant, and Equipment.

Renewable Generation

Our electric utilities meet a portion of their electric generation supply with various renewable energy resources, including wind, hydroelectric, biomass, and in the future, solar projects. 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 customers who wish to access a large-scale renewable project located in Wisconsin that WE would operate. The project will contribute toward meeting WE's peak demand, adding up to 150 MW of renewables to WE's portfolio.

Solar

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 and will allow non-profit and government entities, as well as commercial and industrial customers to site solar arrays on their property. Under this program, in 2019, WE constructed 5 MW of solar generation and expects to construct more than double that amount in 2020.

As part of our commitment to invest in zero-carbon generation, we have either filed for or received approval to invest in 300 MW of utility-scale solar within our Wisconsin segment.

- In April 2019, WPS, along with an unaffiliated utility, received approval from the PSCW to acquire ownership interests in two utility-scale solar projects in Wisconsin. Badger Hollow I is located in Iowa County, Wisconsin, and Two Creeks is located in Manitowoc County, Wisconsin. Once constructed, WPS will own 100 MW of the output of each project for a total of 200 MW. Construction began at Two Creeks and Badger Hollow I in August 2019 and October 2019, respectively. Commercial operation of both projects is targeted for the end of 2020.

- In August 2019, WE, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire an ownership interest in a proposed solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin. At its meeting on February 20, 2020, the PSCW approved the acquisition of this project. The approval is still subject to WE's receipt and review of a final written order from the PSCW. Once constructed, WE will own 100 MW of the output of this project. Commercial operation of Badger Hollow II is targeted for the end of 2021.

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 a 16.8% installed capacity reserve margin requirement for the planning year from June 1, 2019, through May 31, 2020, and an 18.0% installed capacity reserve margin requirement for the planning year from June 1, 2020, through May 31, 2021. 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 enough 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, 2020, through May 31, 2021. 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 of our Wisconsin and Michigan jurisdictions, 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 allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs that exceed 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 were as follows for the years ended December 31:

	2019	2018	2017
Coal	**$ 22.77**	$ 23.54	$ 23.05
Natural gas combined cycle	**19.55**	21.69	22.65
Natural gas/oil peaking units	**51.80**	49.06	53.91
Biomass	**102.99**	97.33	118.76
Purchased power	**42.53**	42.85	42.12

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 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 2020, all of our total projected coal requirements of 10.1 million tons are contracted under fixed-price contracts. See Note 23, 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. We have not entered into any coal contracts for years after 2022.

(in thousands)	**Annual Tonnage**
2020	10,020
2021	4,640
2022	2,100

Coal Deliveries

All of our 2020 coal requirements are expected to be shipped by our owned or leased unit trains 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 are 1,387 MW for 2020, 1,379 MW for 2021, and 1,133 MW per year for 2022 through 2024, which exclude planning capacity purchases. These amounts include 1,033 MW per year related to a long-term power purchase agreement for electricity generated by Point Beach. As part of our generation reshaping plan, we recently retired some of our older, less efficient coal-fired generation. 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, WG, and WPS 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 governmental, food products, paper, education, and metals manufacturing. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Operating Income for information on natural gas sales volumes by customer class in Wisconsin and the Upper Peninsula of Michigan.

Operating Revenues

The following table shows natural gas utility operating revenues for our Wisconsin segment disaggregated by customer class for the year ended December 31, 2017. For information about our operating revenues disaggregated by customer class for the years ended December 31, 2019 and 2018, see Note 4, Operating Revenues.

(in millions)	2017
Operating revenues	
Residential	$ 809.3
Commercial and industrial	395.5
Total retail revenues	1,204.8
Transport	72.6
Other operating revenues *	(7.2)
Total operating revenues	$ 1,270.2

* Includes amounts refunded to customers for purchased gas adjustment costs.

Natural Gas Sales Forecast

Our combined Wisconsin service territories experienced growth in weather-normalized retail natural gas deliveries (excluding natural gas deliveries for electric generation) in 2019 due to customer growth. We currently forecast retail natural gas delivery volumes to grow at a rate between 0.5% and 1.0% over the next five years, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	2019	2018	2017
Customers – end of year			
Residential	**1,339.6**	1,329.6	1,318.3
Commercial and industrial	**131.5**	130.6	129.7
Transport	**3.2**	3.0	2.8
Total customers	**1,474.3**	1,463.2	1,450.8

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 23, Commitments and Contingencies.

Pipeline Capacity and Storage

The interstate pipelines serving Wisconsin originate in major natural gas producing areas of North America: the Oklahoma and Texas basins, western Canada, and the Rocky Mountains. 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, we have also contracted for substantial underground storage capacity, primarily in Michigan. 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.

In June 2017, we completed the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. See Note 2, Acquisitions, for more information on this transaction.

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. Subject to PSCW approval, each facility would provide approximately one billion cubic feet of natural gas supply to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity. Commercial operation of the LNG facilities is targeted for the end of 2023.

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 34.1 million therms for the 2019 through 2020 heating season. Our Wisconsin segment natural gas utilities' peak daily send-out during 2019 was 26.4 million therms on January 30, 2019.

Natural Gas Supply

We have contracts with suppliers for natural gas acquired in the Chicago, Illinois market hub and in 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. PGL and NSG, both Illinois corporations, began operations in 1855 and 1900, respectively. Our customers are located in Chicago and the northern suburbs of Chicago. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Illinois Segment Contribution to Operating Income for information on natural gas sales volumes by customer class.

Illinois Utilities Operating Statistics

Operating Revenues

The following table shows natural gas operating revenues for our Illinois utilities disaggregated by customer class for the year ended December 31, 2017. For information about our operating revenues disaggregated by customer class for the years ended December 31, 2019 and 2018, see Note 4, Operating Revenues.

(in millions)	**2017**
Operating revenues	
Residential	$ 934.8
Commercial and industrial	156.7
Total retail revenues	1,091.5
Transport	246.9
Other operating revenues	17.1
Total operating revenues	$ 1,355.5

Customers

	Year Ended December 31		
(in thousands)	**2019**	**2018**	**2017**
Customers – end of year			
Residential	**870.6**	863.2	849.8
Commercial and industrial	**71.8**	72.1	72.9
Transport	**88.7**	97.5	107.5
Total customers	**1,031.1**	1,032.8	1,030.2

Natural Gas Supply, Pipeline Capacity, and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value. For more information on our natural gas utility supply and transportation contracts, see Note 23, 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 26.2 million therms for the 2019 through 2020 heating season. Our Illinois utilities' peak daily send-out during 2019 was 22.6 million therms on January 30, 2019.

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 25, Regulatory Environment.

Other States Segment

Our other states segment includes the natural gas utility operations of MERC and MGU. MERC serves customers in various cities and communities throughout Minnesota, and MGU serves customers in southern and western Michigan. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Other States Segment Contribution to Operating Income for information on natural gas sales volumes by customer class for this segment.

Other States Utilities Operating Statistics

Operating Revenues

The following table shows natural gas operating revenues for our other states utilities disaggregated by customer class for the year ended December 31, 2017. For information about our operating revenues disaggregated by customer class for the years ended December 31, 2019 and 2018, see Note 4, Operating Revenues.

(in millions)	2017
Operating revenues	
Residential	$ 220.2
Commercial and industrial	123.9
Total retail revenues	344.1
Transport	31.4
Other operating revenues	35.7
Total operating revenues	$ 411.2

Customers

(in thousands)	Year Ended December 31 2019	2018	2017
Customers – end of year			
Residential	**360.8**	356.5	353.0
Commercial and industrial	**35.0**	34.9	34.5
Transport	**24.7**	24.7	24.2
Total customers	**420.5**	416.1	411.7

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 23, Commitments and Contingencies.

Pipeline Capacity and Storage

We own a storage field (Partello in Michigan) and contract 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 8.7 million therms for the 2019 through 2020 heating season. Our other states utilities' peak daily send-out during 2019 was 8.4 million therms on January 30, 2019.

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. 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. However, during the polar vortex in the first quarter of 2019 we curtailed electric service to certain non-firm customers at MISO's request, in response to wide-spread regional power supply issues in MISO. These non-firm customers receive a rate credit in return for agreeing to occasional service interruptions. WPS also had service curtailments for economic interruptions during this period. 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.

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.

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, 2019, our ownership interest in ATC was approximately 60%. In addition, 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 20, Investment in Transmission Affiliates, for more information.

In November 2019, the FERC issued an order related to the methodology used to calculate the 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 – Other 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 our ownership interests in the Bishop Hill III, Upstream, and Coyote Ridge 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 ERGS units, ER 1 and ER 2, which were placed in service in February 2010 and January 2011, respectively, and the 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), and are positioned to provide a significant portion of our future generation needs.

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, 2019, our non-utility energy infrastructure segment included WECI's ownership interests in the three wind generating facilities reflected in the table below.

Name	Ownership Interest
Upstream (1)	80.0%
Bishop Hill III	90.0%
Coyote Ridge (2)	80.0%

(1) In February 2020, WECI signed an agreement to acquire an additional 10% ownership interest in Upstream.

(2) Coyote Ridge achieved commercial operation on December 20, 2019.

Bishop Hill III and Coyote Ridge have long-term offtake agreements with unaffiliated 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 an unaffiliated third party. Under the Tax Legislation, all of these investments qualify for production tax credits and 100% bonus depreciation. WECI is entitled to the tax benefits of each facility in proportion to its ownership interest, with the exception of Coyote Ridge. WECI is entitled to 99% of the tax benefits of Coyote Ridge for the first 11 years of commercial operation, after which WECI will be entitled to tax benefits equal to its ownership interest. WECI recognizes production tax credits 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 addition, in January 2020, WECI signed an agreement to acquire an 80% ownership interest in Blooming Grove, a 250 MW wind generating facility under construction in Illinois. In February 2020, WECI amended these agreements to acquire an additional 10% ownership interest in both Thunderhead and Blooming Grove. Under the Tax Legislation, WECI's investments in Thunderhead and Blooming Grove are expected to qualify for production tax credits and 100% bonus depreciation.

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

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, Bostco (prior to the sale of substantially all of its remaining assets in the first quarter of 2017 and its dissolution in October 2018), WBS, and PDL. See Note 3, Dispositions, for more information on the sale of Bostco's assets and certain assets of PDL. This segment also includes Wisvest and WECC, which no longer have significant operations.

Wispark develops and invests in real estate, primarily in southeastern Wisconsin. Wispark had $32.9 million in real estate holdings at December 31, 2019.

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.

PDL owns distributed renewable solar projects. As part of our asset management strategy, in 2019, PDL sold its remaining four distributed commercial and industrial solar projects. See Note 3, Dispositions, for more information on these sales. These facilities were not considered core to our operations. PDL still owns a portfolio of residential solar systems.

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 (previously Michigan Department of Environmental Quality); 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 were regulated by the various commissions shown in the table below during 2019. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Regulated Rates	Regulatory Commission
WE	
Retail electric, natural gas, and steam	PSCW
Retail electric *	MPSC
Wholesale power	FERC
WPS	
Retail electric and natural gas	PSCW
Wholesale power	FERC
WG	
Retail natural gas	PSCW
UMERC	
Retail electric and natural gas	MPSC
Wholesale power	FERC
PGL	
Retail natural gas	ICC
NSG	
Retail natural gas	ICC
MERC	
Retail natural gas	MPUC
MGU	
Retail natural gas	MPSC

* Tilden, an iron-ore mine in the Upper Peninsula of Michigan, was a customer of WE through March 31, 2019. Tilden became a customer of UMERC when UMERC's new natural gas-fired generation in the Upper Peninsula began commercial operation. As a result, WE no longer has any retail customers in Michigan and its retail electric rates were not regulated by the MPSC after March 31, 2019. See Note 25, Regulatory Environment, for more information on the formation of UMERC.

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 and our wholesale 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 in 2019 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts.

WE, WPS, and WG are each subject to an earnings sharing mechanism. WE and WG have been subject to an earnings sharing mechanism since January 2016, and WPS adopted one in January 2018 pursuant to its settlement agreement with the PSCW. See Note 25, Regulatory Environment, for more information.

For information on how rates are set for our regulated entities, see Note 25, 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/
FERC	http://www.ferc.gov/

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.

The following table compares our utility operating revenues by regulatory jurisdiction for each of the three years ended December 31:

	2019		2018		2017	
(in millions)	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Electric						
Wisconsin	**$ 3,807.4**	**88.2%**	$ 3,890.4	87.7%	$ 3,909.1	85.7%
Michigan	**142.6**	**3.3%**	152.4	3.4%	145.9	3.2%
FERC – Wholesale	**367.6**	**8.5%**	396.1	8.9%	504.0	11.1%
Total	**4,317.6**	**100.0%**	4,438.9	100.0%	4,559.0	100.0%
Natural Gas						
Wisconsin	**1,325.3**	**42.6%**	1,351.8	42.3%	1,266.4	41.7%
Illinois	**1,357.1**	**43.6%**	1,400.0	43.8%	1,355.5	44.6%
Minnesota	**281.5**	**9.0%**	289.8	9.1%	272.6	9.0%
Michigan	**148.7**	**4.8%**	152.4	4.8%	142.4	4.7%
Total	**3,112.6**	**100.0%**	3,194.0	100.0%	3,036.9	100.0%
Total utility operating revenues	**$ 7,430.2**		$ 7,632.9		$ 7,595.9	

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC-approved RTO, MISO operates bid-based energy markets. MISO has been able to assume significant balancing area responsibilities such as frequency control and disturbance control.

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 the LMP system that is used in certain northeastern and mid-Atlantic states. 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, 2019, through May 31, 2020. 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, 2019, through May 31, 2020 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, Coyote Ridge, and Upstream are all subject to the FERC's regulation of wholesale energy under the Federal Power Act.

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 – Capital 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 23, Commitments and Contingencies.

G. EMPLOYEES

As of December 31, 2019, we had the following number of employees:

	Total Employees
WE	2,562
WPS	1,190
WG	392
PGL	1,497
NSG	150
MERC	217
MGU	146
WBS	1,355
Total employees	7,509

As of December 31, 2019, we had employees represented under labor agreements with the following bargaining units:

	Number of Employees	Expiration Date of Current Labor Agreement
WE		
Local 2150 of International Brotherhood of Electrical Workers	1,547	August 15, 2020
Local 420 of International Union of Operating Engineers	351	September 30, 2021
Local 2006 Unit 1 of United Steel Workers of America	103	October 31, 2021
Local 510 of International Brotherhood of Electrical Workers	4	October 31, 2020
Total WE	2,005	
WPS		
Local 420 of International Union of Operating Engineers	858	April 16, 2021
WG		
Local 2150 of International Brotherhood of Electrical Workers	87	August 15, 2020
Local 2006 Unit 1 of United Steel Workers of America	184	October 31, 2021
Total WG	271	
PGL		
Local 18007 of Utility Workers Union of America	945	April 30, 2023
Local 18007(C) of Utility Workers Union of America	59	July 31, 2021
Total PGL	1,004	
NSG		
Local 2285 of International Brotherhood of Electrical Workers	103	June 30, 2024
MERC		
Local 31 of International Brotherhood of Electrical Workers	44	May 31, 2020
Local 49 of International Union of Operating Engineers	3	January 1, 2022
Total MERC	47	
MGU		
Local 12295 of United Steelworkers of America *	68	January 15, 2023
Local 417 of Utility Workers Union of America	24	February 15, 2022
Total MGU	92	
Total represented employees	4,380	

* A three year contract was ratified between MGU and the Union Steelworkers of America, Local 12295, on January 11, 2020.

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 regulation, including regulation 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.

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 numerous federal and state environmental laws and regulations. These laws and regulations govern, 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, toxic, and solid wastes and substances. We incur significant costs to comply with these environmental requirements, including costs associated with the installation of pollution control equipment, environmental monitoring, emissions fees, and permits at our facilities. In addition, if we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines.

The EPA adopted and implemented (or is in the process of implementing) regulations governing the emission of NOx, SO_2, fine particulate matter, mercury, and other air pollutants under the CAA through the NAAQS, the MATS rule, the ACE rule, the Cross-State Air Pollution rule, and other air quality regulations. In addition, the EPA 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. We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations. In addition, as a result of the upcoming 2020 federal Presidential election and the lack of final resolution of several environmental standards, there is uncertainty as to what capital expenditures or additional costs may ultimately be required to comply with existing and future environmental laws and regulations.

Existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal or state level that could result in significant additional expenditures for our generation units or distribution systems, including, without limitation, costs to further limit GHG emissions from our operations; operating restrictions on our facilities; and increased compliance costs. In addition, the operation of emission control equipment and compliance with rules regulating our intake and discharge of water could increase our operating costs and reduce the generating capacity of our power plants. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could affect the availability and/or cost of fossil fuels.

As a result of these environmental laws and regulations 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. We retired approximately 1,800 MW of coal-fired generation since the beginning of 2018, including the 2018 retirements of the Pleasant Prairie power plant, Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit and the 2019 retirement of the PIPP. Certain of our remaining coal-fired electric generating facilities may also be retired or converted in the future. If other generation facility owners in the Midwest retire a significant number of older coal-fired generation facilities, a potential reduction in the region's capacity reserve margin below acceptable risk levels may result. This could impair the reliability of the grid in the Midwest, particularly during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

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, 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 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.

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.

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, has become more frequent throughout the United States. 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 significant adverse effect on our results of operations and financial condition.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Management believes it is reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change, and the role of human activity in it, will continue, with the potential for further regulation that affects our operations.

The ACE rule became effective in September 2019 and is currently being litigated by multiple states (including Illinois, Michigan, Minnesota, and Wisconsin), local governments, and non-government organizations. This rule provides existing coal-fired generating units with standards for achieving GHG emission reductions. Every state's plan to implement ACE is required to focus on reducing GHG emissions by improving the efficiency of fossil-fueled power plants. We are continuing to analyze the GHG emission profile of our electric generation resources and to work with other stakeholders to determine the potential impacts to our operations of the ACE rule and federal and state GHG regulations in general.

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. GHG regulations that may be adopted in the future, at either the federal or state level, 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. These regulations could also adversely affect our future results of operations, cash flows, and financial condition.

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. As a result, future regulation of 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.

We also continue to monitor the feasibility of taking more aggressive action to further reduce GHG emissions in order to limit future global temperature increases. 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 federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our or our subsidiaries' credit ratings.

We and our subsidiaries have invested or will be investing in renewable energy generating facilities, several of which generate production tax credits and investment tax credits that we use to reduce our federal tax obligations. The amount of tax credits we earn depends on the level of electricity generated, the applicable tax credit rate, and the amount of the investment in qualifying property. If our tax credits were disallowed in whole or in part as a result of an IRS audit or changes in tax law, we could owe tax liabilities for previously recognized tax credits that could significantly impact our earnings and cash flows.

In addition, if corporate tax rates or policies are changed with future federal or state legislation, we may be required to take material charges against earnings. For example, the Tax Legislation significantly changed the United States Internal Revenue Code, including taxation of United States corporations, by, among other things, reducing the federal corporate income tax rate, limiting interest deductions, and altering the expensing of capital expenditures. Parts of the Tax Legislation still remain unclear and will require additional interpretations and implementing regulations by the Treasury Department and the IRS, as well as state income tax authorities, and the Tax Legislation could continue to be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the Tax Legislation. State and local taxing authorities continue to evaluate the impact of the Tax Legislation, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

There is still uncertainty as to when or how credit rating agencies, capital markets, the FERC, or state public utility commissions will treat any additional impacts of the Tax Legislation. These impacts could subject us or any of our subsidiaries to further credit rating downgrades. It is unclear whether additional opportunities may evolve for us to manage the adverse impacts of the Tax Legislation. In addition, certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted by future rulings related to the Tax Legislation.

Based on our current evaluation of the Tax Legislation, we do not expect the limitations on interest deductions to materially adversely affect our earnings per share. Any amendments to the Tax Legislation or interpretations or implementing regulations by the Treasury Department and/or the IRS contrary to our interpretation of the Tax Legislation could limit our ability to deduct the interest on some of our outstanding debt.

There may be other material adverse effects resulting from the Tax Legislation that we have not yet identified. If we are unable to successfully take actions to manage any adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments, or technical corrections exacerbate the adverse impacts of the Tax Legislation, the Tax Legislation could have an adverse effect on our financial condition, results of operations, cash flows, and on the value of investments in our debt securities and common stock, and could result in credit rating agencies placing our or our subsidiaries’ credit ratings on negative outlook or further downgrading our or our subsidiaries' credit ratings.

We may fail to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act.

We are subject to reporting, disclosure control, and other obligations under SOX. SOX contains provisions requiring our management to report on the effectiveness of our internal control over financial reporting and requires our independent registered public accounting firm to attest to the effectiveness of our internal controls. We have undertaken, and will continue to undertake, a variety of initiatives to integrate, standardize, centralize, and streamline our operations with technology, including, but not limited to, the implementation of several different ERP systems. There is a risk that we will not be able to conclude that our internal control over financial reporting is effective because of the discovery of material weaknesses, with either our current controls and processes or with the implementation of new controls and processes around these new technologies. Any failure to maintain effective internal controls or a determination by our independent registered public accounting firm that we have a material weakness in our internal controls could cause investors to lose confidence in the accuracy or completeness of our financial reports, cause a decline in the market price of our common stock, restrict our access to the capital markets, or subject us to investigations by the SEC or other regulatory authorities.

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 were ever found to be in noncompliance with the mandatory reliability standards, they could be subject to sanctions, including substantial monetary penalties.

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 exceptions.

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

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

Our financial performance depends on the successful operation of our electric generation and natural gas and electric distribution 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; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, 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.

Because our electric generation 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 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 by certain dates.

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.

We are actively involved with several 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 investing in renewable energy generating facilities as part of our generation reshaping plan 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. These 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; the impact on global supply chains 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 production tax credits and investment tax credits 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, but these 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 against our generation facilities, electric and natural gas distribution infrastructure, our information and technology systems, and network infrastructure, including that of third parties on which we rely, 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. 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, including but not limited to, a customer information and billing system, automated meter reading systems, and other similar technological tools and initiatives. 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.

Any operational disruption or environmental repercussions caused by these on-going 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 could make our electric generating facilities less competitive.

Advances in new technologies that produce 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 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, and solar cells, 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. 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 power production. If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities could be reduced. Advances in technology could also change the channels through which our electric customers purchase or use power, 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 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 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. 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, 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, 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, and transportation agreements with non-affiliated companies, and continue to look for additional opportunities to enter into these agreements. Revenues are dependent on the continued performance by the counterparties of their obligations under the power purchase, natural gas supply, and transportation 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 under these agreements. 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, 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.

We may not be able to fully use tax credits, net operating losses, and/or charitable contribution carryforwards.

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits, net operating losses, and charitable contribution deductions available under the applicable tax codes. We have not fully used the allowed tax credits, net operating losses, and charitable contribution deductions in our previous tax filings. We may not be able to fully use the tax credits, net operating losses, and charitable contribution deductions available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit their use. In addition, any future disallowance of some or all of those tax credits, net operating losses, or charitable contribution carryforwards as a result of legislation or an adverse determination by one of the applicable taxing jurisdictions could materially affect our tax obligations and financial results.

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, 2019, our goodwill was $3,052.8 million.

Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access capital markets.

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. 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. In addition, we rely on committed bank credit agreements as back-up liquidity, which allows us to access the low cost commercial paper markets.

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;
- 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;
- War or the threat of war;
- The overall health and view of the utility and financial institution industries; and
- Changes in the method of determining LIBOR or the replacement of LIBOR with an alternative reference rate.

A portion of our indebtedness bears interest at variable interest rates, primarily based on LIBOR. LIBOR is the subject of recent national, international, and other regulatory guidance and proposals for reform, which may cause LIBOR to cease to exist after 2021 or to perform differently than in the past. While we expect that reasonable alternatives to LIBOR will be implemented prior to the

2021 target date, we cannot predict the consequences and timing of the development of alternative reference rates. The transition to alternative reference rates could include an increase in our interest expense and/or reduction in our interest income.

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.

See the risk factor titled "Changes in federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our or our subsidiaries' credit ratings" above for information about how the Tax Legislation could impact our or our subsidiaries' credits ratings.

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 may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations 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 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. 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 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. This increased competition in the retail and wholesale markets could have a significant adverse financial impact on us.

Certain jurisdictions in which we operate, including Michigan and Illinois, have adopted retail choice. Under Michigan law, our retail 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.

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, 2019:

Name	Location	Fuel	Number of Generating Units	Rated Capacity In MW (1)	
Coal-fired plants					
Columbia	Portage, WI	Coal	2	314	(2)
ERGS	Oak Creek, WI	Coal	2	1,054	(3) (4)
OCPP	Oak Creek, WI	Coal	4	1,075	
Weston	Rothschild, WI	Coal	2	715	(2)
Total coal-fired plants			10	3,158	
Natural gas-fired plants					
Concord Combustion Turbines	Watertown, WI	Natural Gas/Oil	4	361	
De Pere Energy Center	De Pere, WI	Natural Gas/Oil	1	167	
Fox Energy Center	Wrightstown, WI	Natural Gas	3	567	
Germantown Combustion Turbines	Germantown, WI	Natural Gas/Oil	5	273	
F. D. Kuester	Negaunee, MI	Natural Gas	7	131	
A. J. Mihm	Baraga, MI	Natural Gas	3	56	
Paris Combustion Turbines	Union Grove, WI	Natural Gas/Oil	4	358	
PWGS	Port Washington, WI	Natural Gas	2	1,228	(4)
Pulliam	Green Bay, WI	Natural Gas/Oil	1	79	
VAPP	Milwaukee, WI	Natural Gas	2	265	
West Marinette	Marinette, WI	Natural Gas/Oil	3	154	
Weston	Rothschild, WI	Natural Gas/Oil	3	114	
Total natural gas-fired plants			38	3,753	
Renewables					
Hydro Plants (30 in number)	WI and MI	Hydro	81	94	(5) (6)
Rothschild Biomass Plant	Rothschild, WI	Biomass	1	46	(7)
Wind Sites (5 in number)	WI and IA	Wind	350	67	(8)
Total renewables			432	207	
Total system			480	7,118	

(1) Capacity for our electric generation 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 2020 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.

(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 27.6% ownership interest in Columbia. See Note 7, Jointly Owned Utility Facilities, for more information on the anticipated decrease in WPS's ownership interest in the Columbia unit.

- 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.

(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 6.8 MW and 10.2 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.

(8) WPS, along with two other unaffiliated utilities, owns Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. WPS is entitled to its share of generating capability and output of the facility equal to its ownership interest of 44.6%. See Note 2, Acquisitions, for more information on the Forward Wind Energy Center acquisition.

As of December 31, 2019, we operated approximately 36,500 miles of overhead distribution lines and approximately 34,100 miles of underground distribution cable, as well as approximately 500 electric distribution substations and approximately 503,200 line transformers.

Natural Gas Facilities

At December 31, 2019, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 49,500 miles of natural gas distribution mains,
- Approximately 1,200 miles of natural gas transmission mains,
- Approximately 2.3 million natural gas lateral services,
- Approximately 510 natural gas distribution and transmission gate stations,
- Approximately 68.2 billion cubic feet of working gas capacities in underground natural gas storage fields:
  - Bluewater, 26.5 billion cubic feet of fields located in southeastern Michigan,
  - Manlove, a 38.8 billion-cubic-foot field located in central Illinois,
  - Partello, a 2.9 billion-cubic-foot field located in southern Michigan,
- A 2.0 billion-cubic-foot 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, Consumers Energy, Enbridge Gas, Great Lakes Transmission Company, Guardian Pipeline L.L.C., Kinder Morgan Illinois Pipeline, Michigan Consolidated Gas Company, Midwestern Gas Pipeline Company, Natural Gas Pipeline Company of America, Nicor Gas, Northern Border Pipeline Company, Northern Natural Gas Company, Panhandle Gas Transmission, Trunkline Gas Pipeline, Vector Pipeline Company, and Viking Gas Transmission. Our LNG storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

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

Steam Facilities

As of December 31, 2019, 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 to WE, WPS, and WG. WECI has ownership interests in three wind generating facilities.

The following table summarizes information on WECI's wind generating facilities as of December 31, 2019:

Name	Location	Number of Generating Units	Nameplate Capacity In MW (1)	
Wind generating facilities				
Upstream	Antelope County, Nebraska	81	202.5	(2)
Bishop Hill III	Henry County, Illinois	53	132.1	(3)
Coyote Ridge	Brookings County, South Dakota	39	96.7	(4)
Total wind generating facilities		173	431.3	

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

(2) In January 2019, WECI completed the acquisition of an 80% ownership interest in Upstream. In February 2020, WECI agreed to acquire an additional 10% ownership interest in Upstream. See Note 2, Acquisitions, for more information.

(3) In August 2018, WECI completed the acquisition of an 80% ownership interest in Bishop Hill III. In December 2018, WECI acquired an additional 10% ownership interest in this wind farm. See Note 2, Acquisitions, for more information.

(4) In December 2018, WECI completed the acquisition of an 80% ownership interest in Coyote Ridge, which achieved commercial operation in December 2019. See Note 2, Acquisitions, for more information.

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. In January 2020, WECI signed an agreement to acquire an 80% ownership interest in Blooming Grove, a 250 MW wind generating facility under construction in McLean County, Illinois. In February 2020, WECI agreed to acquire an additional 10% ownership interest in both Thunderhead and Blooming Grove. See Note 2, Acquisitions, for more information on the pending acquisitions.

ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 23, Commitments and Contingencies, and Note 25, 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 23, Commitments and Contingencies, Note 25, 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 effect 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, which PGL submitted to the IEPA in August 2019. The GMZ application is being reviewed by the IEPA staff.

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 wishes to consider such penalties, 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 at December 31, 2019 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.

Gale E. Klappa. Age 69.
- 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. Director since December 2003. President from April 2003 to August 2013.
- 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 August 2003 to June 2015.

J. Kevin Fletcher. Age 61.
- WEC Energy Group — Director and Chief Executive Officer since February 2019. President since October 2018.
- WE — Chairman of the Board and Chief Executive Officer since February 2019. Director since June 2015. President from May 2016 to November 2018. Executive Vice President - Customer Service and Operations from June 2015 to April 2016. Senior Vice President - Customer Operations from October 2011 to June 2015.

Robert M. Garvin. Age 53.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.
- WE — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.

William J. Guc. Age 50.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- WE — Vice President and Controller since October 2015.
- Integrys Energy Group — Vice President and Treasurer from December 2010 to June 2015.

Margaret C. Kelsey. Age 55.
- 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.

Daniel P. Krueger. Age 54.
- WEC Energy Group — Executive Vice President - WEC Infrastructure since November 2018.
- WE — Senior Vice President - Wholesale Energy and Fuels from June 2015 to January 2019. Vice President from May 2014 to June 2015.

Frederick D. Kuester.* Age 69.
- WEC Energy Group — Senior Executive Vice President since March 2018. Executive Vice President from May 2004 to January 2013.
- WE — Executive Vice President from May 2004 to January 2013.

Scott J. Lauber. Age 54.
- WEC Energy Group — Senior Executive Vice President and Chief Financial Officer since October 2019. 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.
- WE — Executive Vice President and Chief Financial Officer since October 2019, and from April 2016 to October 2018. Director since April 2016. Executive Vice President, Chief Financial Officer and Treasurer from October 2018 to October 2019. Vice President and Treasurer from February 2013 to March 2016.

Charles R. Matthews. Age 63.
- 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.
- WE — Senior Vice President - Wholesale Energy and Fuels from January 2012 to June 2015.

Tom Metcalfe. Age 52.
- WE — President since November 2018. Director since January 2018. Executive Vice President - Generation from April 2016 to November 2018. Senior Vice President - Power Generation from January 2014 to March 2016.

Anthony L. Reese. Age 38.
- WEC Energy Group — Vice President and Treasurer since October 2019.
- WE — Vice President and Treasurer since October 2019.
- Controller - Illinois from September 2015 to September 2019. Manager - Financial Planning and Analysis from May 2011 to September 2015.

Mary Beth Straka. Age 55.
- WEC Energy Group — Senior Vice President - Corporate Communications and Investor Relations since June 2015.
- WE — Senior Vice President - Corporate Communications and Investor Relations from June 1 to June 28, 2015.
- Barclays — Vice President of Equity Research Power and Utilities Group from September 2008 to May 2015.

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

* On January 31, 2020, Mr. Kuester informed the Company of his intent to retire in 2020.

PART II

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

Number of Common Shareholders

As of January 31, 2020, based upon the number of WEC Energy Group shareholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 45,000 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 10, Common Equity.

ITEM 6. SELECTED FINANCIAL DATA

WEC ENERGY GROUP, INC.
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 *(in millions, except per share information)*	**2019**	**2018**	**2017 (1)**	**2016**	**2015 (2)**
Operating revenues	**$ 7,523.1**	$ 7,679.5	$ 7,648.5	$ 7,472.3	$ 5,926.1
Net income attributed to common shareholders	**1,134.0**	1,059.3	1,203.7	939.0	638.5
Total assets	**34,951.8**	33,475.8	31,590.5	30,123.2	29,355.2
Preferred stock of subsidiary	**30.4**	30.4	30.4	30.4	30.4
Long-term debt (excluding current portion)	**11,211.0**	9,994.0	8,746.6	9,158.2	9,124.1
Weighted average common shares outstanding					
Basic	**315.4**	315.5	315.6	315.6	271.1
Diluted	**316.7**	316.9	317.2	316.9	272.7
Earnings per share					
Basic	**$ 3.60**	$ 3.36	$ 3.81	$ 2.98	$ 2.36
Diluted	**$ 3.58**	$ 3.34	$ 3.79	$ 2.96	$ 2.34
Dividends per share of common stock	**$ 2.36**	$ 2.21	$ 2.08	$ 1.98	$ 1.74

(1) Includes a $206.7 million increase in net income attributed to common shareholders related to a re-measurement of our deferred taxes as a result of the Tax Legislation. See Note 15, Income Taxes, for more information.

(2) Includes the impact of the Integrys acquisition for the last two quarters of 2015.

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 FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through We Power (which owns generation assets in Wisconsin), Bluewater (which owns underground natural gas storage facilities in Michigan), and WEC Infrastructure LLC (WECI), which holds ownership interests in several wind generating facilities.

In August 2019, WECI signed an agreement to acquire an 80% ownership interest in Thunderhead Wind Energy LLC, a 300 MW wind generating facility under construction in Antelope and Wheeler counties in Nebraska. In January 2020, WECI signed an agreement to acquire an 80% ownership interest in Blooming Grove Wind Energy Center LLC, a 250 MW wind generating facility under construction in McLean County, Illinois. See Note 2, Acquisitions, for more information.

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: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

The planned reshaping of our generation fleet balances reliability and customer cost with environmental stewardship. Taken as a whole, this plan should reduce costs to customers, preserve fuel diversity, and lower carbon emissions. Generation reshaping includes retiring older fossil fuel generation units, building state-of-the-art natural gas generation, and investing in cost-effective zero-carbon generation. In 2019, we met and exceeded our 2030 goal of reducing CO_2 emissions by 40% below 2005 levels, and are re-evaluating our longer-term CO_2 reduction goals. We have already retired more than 1,800 MW of coal-fired generation since the beginning of 2018, and expect to continue adding natural gas-fired generating units and renewable generation, including utility-scale solar projects. The plan included the March 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, Property, Plant, and Equipment, for more information related to these power plant retirements.

As part of our commitment to invest in zero-carbon generation, we have either filed for or received approval 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 in Wisconsin. Badger Hollow Solar Farm I is located in Iowa County, Wisconsin, and the Two Creeks Solar Project is located in Manitowoc County, Wisconsin. Once constructed, WPS will own 100 MW of the output of each project for a total of 200 MW. The Public Service Commission of Wisconsin (PSCW) approved the acquisition of these two projects in April 2019. Construction began at the Two Creeks Solar Project and the Badger Hollow Solar Farm I in August 2019 and October 2019, respectively. Commercial operation of both projects is targeted for the end of 2020. Wisconsin Electric Power Company (WE) has partnered with an unaffiliated utility to acquire an ownership interest in a proposed solar project, Badger Hollow Solar Farm II, that will be located in Iowa County, Wisconsin. At its meeting on February 20, 2020, the PSCW approved the acquisition of this project. The approval is still subject to WE's receipt and review of a final written order from the PSCW. Once constructed, WE will own 100 MW of the output of this project. Commercial operation of Badger Hollow Solar Farm II is targeted for the end of 2021.

In December 2018, WE received approval from the PSCW for two renewable energy pilot programs. The Solar Now pilot 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, in 2019, WE constructed 5 MW of solar generation and expects to construct more than double that amount in 2020. 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 allowing these larger customers to meet their sustainability and renewable energy goals.

As the cost of renewable energy generation continues to decline, these utility-scale solar projects and the WE pilot programs have become cost effective opportunities for WEC Energy Group and our customers to participate in renewable energy.

We also have a goal to decrease the rate of methane emissions from the natural gas distribution lines in our network by 30% per mile by the year 2030 from a 2011 baseline. We were over half way toward meeting that goal at the end of 2019.

Reliability

We have made significant reliability-related investments in recent years, and plan to continue strengthening and modernizing our generation fleet and distribution networks to further improve reliability. Our investments, coupled with our commitment to operating efficiency and customer care, resulted in We Energies and WPS being recognized by PA Consulting Group, an independent consulting firm, for superior reliability of their electric delivery networks. This is the ninth consecutive year that We Energies has been named the most reliable utility in the Midwest and the first time WPS has been recognized.

Below are a few examples of reliability projects that are proposed or currently underway.

- WE and Wisconsin Gas LLC (WG) each plan to construct their own LNG facility. Subject to PSCW approval, each facility would provide approximately one billion cubic feet 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. Commercial operation of the LNG facilities is targeted for the end of 2023.

- The Peoples Gas Light and Coke Company continues to work on its Natural Gas System Modernization Program, which primarily involves replacing old cast and ductile 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 continues work on its System Modernization and Reliability Project, which involves modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WE, WPS, and WG also continue to upgrade their electric and natural gas distribution systems to enhance reliability.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. 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 resources of all our businesses and finding the best and most efficient processes while meeting all applicable legal and regulatory requirements. We also strive to provide the best value to our customers and shareholders by embracing constructive change, leveraging capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations.

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 2, Acquisitions, for information about our acquisitions of portions of wind energy generation facilities in Wisconsin, Illinois, Nebraska, and South Dakota.

- See Note 3, Dispositions, for information on recent dispositions. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco LLC, and, in October 2018, Bostco was dissolved. In 2019, we sold certain WPS Power Development, LLC solar power generation facilities.

Our investment focus remains in our regulated utility and non-utility energy infrastructure businesses, as well as our investment in ATC. We expect total capital expenditures for our regulated utility and non-utility energy infrastructure businesses to be approximately $13.7 billion from 2020 to 2024. Specific projects are discussed in more detail below under Liquidity and Capital Resources.

From 2020 to 2024, we expect capital contributions to ATC to be approximately $150 million. Capital investments at ATC will be funded utilizing these capital contributions, in addition to cash generated by ATC from operations and debt. We currently forecast that our share of ATC's projected capital expenditures over the next five years will be $1.3 billion.

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 embracing constructive change, demonstrating personal responsibility for results, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers’ expectations.

Safety

We have a long-standing commitment to both workplace and public safety, and under our "Target Zero" mission, we have an ultimate goal of zero incidents, accidents, and injuries. We also set goals around injury-prevention activities that raise awareness and facilitate conversations about employee safety. 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, 2019 with the year ended December 31, 2018. For a similar discussion that compares our results for the year ended December 31, 2018 with the year ended December 31, 2017, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations in Part II of our 2018 Annual Report on Form 10-K.

Consolidated Earnings

The following table compares our consolidated results for the year ended December 31, 2019 with the year ended December 31, 2018, including favorable or better, "B", and unfavorable or worse, "W", variances:

	Year Ended December 31					
(in millions, except per share data)	2019	2018	B (W)	Change Related to Flow Through of Tax Repairs	Change Related to Adoption of New Lease Guidance (Topic 842)	Remaining Change B (W)
Wisconsin	**$ 1,189.6**	$ 800.2	$ 389.4	$ (3.1)	$ 350.9	$ 41.6
Illinois	**291.9**	255.8	36.1	—	—	36.1
Other states	**65.3**	68.8	(3.5)	—	—	(3.5)
Non-utility energy infrastructure	**366.6**	365.8	0.8	—	—	0.8
Corporate and other	**(34.4)**	(22.2)	(12.2)	—	—	(12.2)
Reconciling eliminations *	**(347.6)**	—	(347.6)	—	(347.6)	—
Total operating income	**1,531.4**	1,468.4	63.0	(3.1)	3.3	62.8
Equity in earnings of transmission affiliates	**127.6**	136.7	(9.1)	—	—	(9.1)
Other income, net	**102.2**	70.3	31.9	—	—	31.9
Interest expense	**501.5**	445.1	(56.4)	—	(3.3)	(53.1)
Income before income taxes	**1,259.7**	1,230.3	29.4	(3.1)	—	32.5
Income tax expense	**125.0**	169.8	44.8	3.1	—	41.7
Preferred stock dividends of subsidiary	**1.2**	1.2	—	—	—	—
Net loss attributed to noncontrolling interests	**0.5**	—	0.5	—	—	0.5
Net income attributed to common shareholders	**$ 1,134.0**	$ 1,059.3	$ 74.7	$ —	$ —	$ 74.7
Diluted earnings per share	**$ 3.58**	$ 3.34	$ 0.24			

* We adopted ASU 2016-02, Leases (Topic 842), effective January 1, 2019, which revised the previous guidance regarding the accounting for leases. As a result of this adoption, during 2019, $347.6 million of minimum lease payments that were billed from We Power to WE were no longer classified within operation and maintenance, but were instead recorded as interest expense in accordance with Topic 842. The We Power leases do not impact our financial statements as all amounts associated with the leases are eliminated at the consolidated level.

Earnings increased $74.7 million during 2019, compared with 2018. The table above shows the income statement impacts associated with the flow through of tax repairs beginning January 1, 2018 and the adoption of Topic 842, effective January 1, 2019. As shown in the table above, the changes related to these items had no impact on net income attributed to common shareholders.

The significant factors impacting the $74.7 million increase in earnings were:

- A $41.7 million remaining decrease in income tax expense, primarily due to an increase in wind production tax credits related to acquisitions of ownership interests in wind generation facilities in our non-utility energy infrastructure segment and the impact of the 2018 PSCW order regarding the benefits associated with the Tax Legislation. The impacts from the 2018 PSCW order related to the Tax Legislation were offset in operating income at the Wisconsin segment. See Note 2, Acquisitions, for more information on the acquisitions in our non-utility energy infrastructure segment.

- A $41.6 million remaining increase in operating income at the Wisconsin segment. The increase was driven by lower operation and maintenance expense related to our power plants, which primarily resulted from lower maintenance and labor costs associated with our 2019 and 2018 plant retirements, and increases to certain plant-related regulatory assets resulting from decisions included in the December 2019 Wisconsin rate orders. The positive impact from lower operation and maintenance expense was partially offset by a decrease in electric margins related to lower retail sales volumes, primarily driven by cooler summer weather during 2019 compared with 2018; higher depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan; and the impact from the PSCW's 2018 order addressing the Tax Legislation, which was offset in income tax expense.

- A $36.1 million increase in operating income at the Illinois segment. The increase was driven by higher natural gas margins at PGL due to continued capital investment in the SMP project under its QIP rider.

- A $31.9 million increase in other income, net, driven by net gains from investments held in the Integrys rabbi trust during 2019, compared with net losses during 2018. These investment gains partially offset benefits costs related to deferred compensation, which are included in other operation and maintenance expense. See Note 16, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust. Also contributing to the increase was higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 19, Employee Benefits, for more information on our benefit costs.

These increases in earnings were partially offset by:

- A $53.1 million remaining increase in interest expense, driven by higher long-term debt balances, primarily used to fund capital investments.

- A $12.2 million increase in operating loss at the corporate and other segment, primarily driven by the transfer of assets from WBS, our centralized services company, to our regulated utilities in 2018. As a result of these transfers, the return on these assets is now recognized within our regulated utility operations. Also contributing to the increase in operating loss was a gain recorded in the third quarter of 2018 that related to the sale of a legacy business.

- A $9.1 million decrease in earnings from our ownership interests in transmission affiliates, driven by the impact of a FERC order issued in November 2019 that addressed complaints related to ATC's allowed ROE. Increased earnings from continued capital investment partially offset the negative impact from the FERC order.

Non-GAAP Financial Measures

The discussions below address the operating income contribution of each of our segments and 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 margin (electric revenues less fuel and purchased power costs) and natural gas margin (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 our segment operating performance. Operating income for each of the last two fiscal years for each of our segments is presented in the “Consolidated Earnings” table above.

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

Wisconsin Segment Contribution to Operating Income

(in millions)	Year Ended December 31 2019	2018	B (W)
Electric revenues	$ **4,317.6**	$ 4,438.9	$ (121.3)
Fuel and purchased power	**1,341.9**	1,418.1	76.2
Total electric margins	**2,975.7**	3,020.8	(45.1)
Natural gas revenues	**1,329.5**	1,355.8	(26.3)
Cost of natural gas sold	**748.0**	792.1	44.1
Total natural gas margins	**581.5**	563.7	17.8
Total electric and natural gas margins	**3,557.2**	3,584.5	(27.3)
Other operation and maintenance	**1,591.3**	2,076.1	484.8
Depreciation and amortization	**617.0**	546.6	(70.4)
Property and revenue taxes	**159.3**	161.6	2.3
Operating income	$ **1,189.6**	$ 800.2	$ 389.4

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

(in millions)	Year Ended December 31 2019	2018	B (W)
Operation and maintenance not included in line items below	$ **670.7**	$ 769.5	$ 98.8
We Power (1)	**140.9**	506.9	366.0
Transmission (2)	**418.1**	420.7	2.6
Transmission expense related to the flow through of tax repairs (3)	**67.2**	77.8	10.6
Transmission expense related to Tax Legislation (4)	**65.3**	67.7	2.4
Regulatory amortizations and other pass through expenses (5)	**160.6**	159.1	(1.5)
Earnings sharing mechanisms (6)	**61.5**	67.5	6.0
Other	**7.0**	6.9	(0.1)
Total other operation and maintenance	$ **1,591.3**	$ 2,076.1	$ 484.8

(1) Represents costs associated with the We Power generation units, including operating and maintenance costs incurred by WE. During 2018, the amount also included the lease payments that were billed from We Power to WE and then recovered in WE's rates. We adopted ASU 2016-02, Leases (Topic 842), effective January 1, 2019, which revised the previous guidance regarding the accounting for leases. As a result of this adoption, during 2019, $363.3 million of lease expense related to the We Power leases with WE was no longer classified within other operation and maintenance, but was instead recorded as $15.8 million and $347.5 million of depreciation and amortization and interest expense, respectively, in accordance with Topic 842. The We Power leases do not impact our financial statements as all amounts associated with the leases are eliminated at the consolidated level.

During 2019, $134.8 million of operating and maintenance 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. During 2018, $485.3 million of both lease and operating and maintenance 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.

(2) Represents transmission expense that we are authorized to collect in rates, in accordance with the PSCW's approval of escrow accounting for ATC and MISO network transmission expenses for our Wisconsin electric utilities. As a result, WE and WPS defer as a regulatory asset or liability the differences between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2019 and 2018, $486.7 million and $438.2 million, respectively, of costs were billed to our electric utilities by transmission providers.

(3) Represents additional transmission expense associated with WE's flow through of tax benefits of its repair-related deferred tax liabilities starting in 2018, in accordance with a settlement agreement with the PSCW, to maintain certain regulatory asset balances at their December 31, 2017 levels. See Note 25, Regulatory Environment, for more information. The decrease in transmission expense associated with the flow through of tax benefits is offset in income taxes.

(4) Represents additional transmission expense associated with the May 2018 PSCW order requiring WE to use 80% of its current 2018 tax benefit, including the amortization associated with the revaluation of deferred taxes, to reduce its transmission regulatory asset balance. See Note 25, Regulatory Environment, for more information.

(5) Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

(6) See Note 25, Regulatory Environment, for more information about our earnings sharing mechanisms.

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

	Year Ended December 31		
	MWh *(in thousands)*		
Electric Sales Volumes	**2019**	**2018**	**B (W)**
Customer class			
Residential	**10,918.6**	11,195.0	(276.4)
Small commercial and industrial *	**12,861.0**	13,186.7	(325.7)
Large commercial and industrial *	**12,601.6**	12,946.5	(344.9)
Other	**164.8**	169.0	(4.2)
Total retail *	**36,546.0**	37,497.2	(951.2)
Wholesale	**3,314.3**	3,612.7	(298.4)
Resale	**6,006.0**	6,019.3	(13.3)
Total sales in MWh *	**45,866.3**	47,129.2	(1,262.9)

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

	Year Ended December 31		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2019**	**2018**	**B (W)**
Customer class			
Residential	**1,195.6**	1,131.1	64.5
Commercial and industrial	**740.9**	733.1	7.8
Total retail	**1,936.5**	1,864.2	72.3
Transport	**1,426.1**	1,411.5	14.6
Total sales in therms	**3,362.6**	3,275.7	86.9

	Year Ended December 31		
	Degree Days		
Weather	**2019**	**2018**	**B (W)**
WE and WG (1)			
Heating (6,556 normal)	**6,835**	6,685	2.2 %
Cooling (739 normal)	**727**	929	(21.7)%
WPS (2)			
Heating (7,381 normal)	**7,723**	7,554	2.2 %
Cooling (514 normal)	**504**	678	(25.7)%
UMERC (3)			
Heating (8,382 normal)	**8,971**	8,611	4.2 %
Cooling (333 normal)	**284**	478	(40.6)%

(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.

2019 Compared with 2018

Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $45.1 million during 2019, compared with 2018. The significant factors impacting the lower electric utility margins were:

- A $54.1 million decrease related to lower sales volumes, primarily driven by cooler summer weather during 2019 compared with 2018. As measured by cooling degree days, 2019 was 21.7% and 25.7% cooler than 2018 in the Milwaukee and Green Bay areas, respectively.

- A $13.7 million decrease in margins associated with WE's flow through of tax benefits of its repair-related deferred tax liabilities starting in 2018 in accordance with a settlement agreement with the PSCW to maintain certain regulatory assets at their December 31, 2017 levels. This decrease in margins was offset in income taxes. See Note 25, Regulatory Environment, for more information.

- A $6.8 million decrease in margins related to savings from the Tax Legislation that we are required to return to customers through bill credits or reductions in other regulatory assets. This decrease in margins did not impact net income as it was offset by the net impact of a $22.0 million decrease in income taxes and a $15.2 million increase in depreciation and amortization expense. We received the PSCW order in May 2018, which required WPS to use 40% of its 2018 and 2019 tax benefits associated with the Tax Legislation to reduce certain regulatory assets. See Note 15, Income Taxes, and Note 25, Regulatory Environment, for more information.

These decreases in margins were partially offset by:

- A $16.3 million increase in margins related to the iron ore mine located in the Upper Peninsula of Michigan. Prior to the transfer of the mine as a full requirements customer of WE to UMERC as of April 1, 2019, the margin from the mine was being deferred for the benefit of Wisconsin retail electric customers, as ordered by the PSCW. On March 31, 2019 when the new generation solution in the Upper Peninsula began commercial operation, a new 20 year agreement with Tilden became effective under which Tilden began purchasing electric power from UMERC. Half of the cost of the generation solution is being recovered from Tilden under this new agreement.

- A $5.3 million increase in margins related to a net decrease in fuel and purchased power costs driven by the commercial operation of UMERC's new generation solution in the Upper Peninsula of Michigan on March 31, 2019. UMERC previously met its market obligations through power purchase agreements.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $17.8 million during 2019, compared with 2018. The most significant factor impacting the higher natural gas utility margins was higher sales volumes, due in part to colder winter weather, customer growth, and higher use per residential customer during 2019, compared with 2018. As measured by heating degree days, 2019 was 2.2% colder than 2018 in the Milwaukee and Green Bay areas.

Operating Income

Operating income at the Wisconsin segment increased $389.4 million during 2019, compared with 2018. This increase was driven by $416.7 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), partially offset by the $27.3 million net decrease in margins discussed above.

The utility segment experienced lower overall operating expenses related to efficiencies and effective cost control. The other significant factors impacting the decrease in operating expenses during 2019, compared with 2018, were:

- A $363.3 million decrease in other operation and maintenance expense resulting from the adoption of the new lease guidance. As discussed in the other operation and maintenance table above, the adoption of Topic 842, effective January 1, 2019, required WE to change the income statement classification of its lease payments related to the We Power leases. During 2019, the minimum lease payments that were billed from We Power to WE were no longer classified within other operation and maintenance, but were instead recorded as a component of depreciation and amortization and interest expense in accordance with Topic 842.

- A $107.6 million decrease in other operation and maintenance expense related to our power plants, driven by lower maintenance and labor costs associated with our 2019 and 2018 plant retirements, and increases to certain plant-related regulatory assets resulting from decisions included in the December 2019 Wisconsin rate orders. Plant retirements included the March 2019 retirement of the PIPP as well as the 2018 retirements of the Pleasant Prairie power plant, Edgewater Unit 4, and Pulliam Units 7 and 8. See Note 6, Property, Plant, and Equipment, for more information on the plant retirements. See Note 25, Regulatory Environment, for more information on the Wisconsin rate orders.

- A $10.6 million decrease in transmission expense in 2019 related to the flow through of tax repairs, as discussed in the other operation and maintenance table above. This decrease in transmission expense was offset in income taxes.

- A $6.0 million decrease in expense related to the earnings sharing mechanisms in place at our Wisconsin utilities. See Note 25, Regulatory Environment, for more information.

These decreases in operating expenses were partially offset by:

- A $70.4 million increase in depreciation and amortization, driven by assets being placed into service as we continue to execute on our capital plan, an increase related to the reduction of certain regulatory assets as a result of the PSCW's May 2018 order addressing the Tax legislation and offset in electric margins above, and additional expense recognized related to the adoption of Topic 842, as discussed in the notes under the other operation and maintenance table above.

- A $16.4 million increase in storm restoration expense during 2019.

- A $16.3 million net increase in benefit costs, primarily related to higher deferred compensation costs during 2019.

Illinois Segment Contribution to Operating Income

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

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Natural gas revenues	**$ 1,357.1**	$ 1,400.0	$ (42.9)
Cost of natural gas sold	**401.4**	480.5	79.1
Total natural gas margins	**955.7**	919.5	36.2
Other operation and maintenance	**461.1**	472.3	11.2
Depreciation and amortization	**181.3**	170.3	(11.0)
Property and revenue taxes	**21.4**	21.1	(0.3)
Operating income	**$ 291.9**	$ 255.8	$ 36.1

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

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Operation and maintenance not included in the line items below	**$ 362.2**	$ 372.9	$ 10.7
Riders *	**97.5**	95.3	(2.2)
Regulatory amortizations *	**(1.5)**	(1.4)	0.1
Other	**2.9**	5.5	2.6
Total other operation and maintenance	**$ 461.1**	$ 472.3	$ 11.2

* These riders and regulatory amortizations are substantially offset in margins and therefore do not have a significant impact on operating income.

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

	Therms *(in millions)*		
Natural Gas Sales Volumes	**2019**	**2018**	**B (W)**
Customer Class			
Residential	**904.8**	896.2	8.6
Commercial and industrial	**368.6**	358.3	10.3
Total retail	**1,273.4**	1,254.5	18.9
Transport	**896.6**	905.1	(8.5)
Total sales in therms	**2,170.0**	2,159.6	10.4

	Degree Days		
Weather *	**2019**	**2018**	**B (W)**
Heating (6,122 normal)	**6,479**	6,327	2.4%

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

2019 Compared with 2018

Natural Gas Utility Margins

Natural gas utility margins at the Illinois segment, net of the $2.2 million impact of the riders referenced in the table above, increased $34.0 million during 2019, compared with 2018. The increase was primarily driven by an increase in revenue at PGL due to continued capital investment in the SMP project under its QIP rider. PGL currently 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. See Note 25, Regulatory Environment, for more information.

Operating Income

Operating income at the Illinois segment increased $36.1 million during 2019, compared with 2018. This increase was driven by the $34.0 million net increase in margins discussed above, as well as $2.1 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), net of the impact of the riders referenced in the table above.

The significant factor impacting the decrease in operating expenses during 2019, compared with 2018, was a $23.2 million decrease in natural gas maintenance costs related to our Illinois utilities’ distribution systems.

This decrease in operating expenses was partially offset by:

- An $11.0 million increase in depreciation and amortization, primarily driven by PGL's continued capital investment in the SMP project.
- An $8.4 million increase in benefit costs, primarily related to higher deferred compensation costs in 2019.

Other States Segment Contribution to Operating Income

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

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Natural gas revenues	**$ 426.0**	$ 438.2	$ (12.2)
Cost of natural gas sold	**217.5**	232.8	15.3
Total natural gas margins	**208.5**	205.4	3.1
Other operation and maintenance	**98.5**	101.0	2.5
Depreciation and amortization	**27.5**	24.1	(3.4)
Property and revenue taxes	**17.2**	11.5	(5.7)
Operating income	**$ 65.3**	$ 68.8	$ (3.5)

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

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Operation and maintenance not included in line items below	**$ 76.4**	$ 76.1	$ (0.3)
Regulatory amortizations and other pass through expenses *	**22.0**	24.8	2.8
Other	**0.1**	0.1	—
Total other operation and maintenance	**$ 98.5**	$ 101.0	$ 2.5

* Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

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

	Therms *(in millions)*		
Natural Gas Sales Volumes	**2019**	**2018**	**B (W)**
Customer Class			
Residential	**345.2**	336.1	9.1
Commercial and industrial	**238.2**	218.5	19.7
Total retail	**583.4**	554.6	28.8
Transport	**777.1**	738.7	38.4
Total sales in therms	**1,360.5**	1,293.3	67.2

	Degree Days		
Weather *	**2019**	**2018**	**B (W)**
MERC			
Heating (7,934 normal)	**8,728**	8,490	2.8 %
MGU			
Heating (6,245 normal)	**6,347**	6,368	(0.3)%

* 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.

2019 Compared with 2018

Natural Gas Utility Margins

Natural gas utility margins increased $3.1 million during 2019, compared with 2018. The increase was primarily driven by higher sales volumes as a result of colder weather and customer growth, as well as capital investment in natural gas utility infrastructure. MERC began recognizing revenue under its new GUIC rider in the second quarter of 2019. The GUIC rider allows MERC to recover previously approved GUIC that were incurred to replace or modify natural gas facilities to the extent the work was required by state, federal, or other government agencies and exceed the costs included in base rates. These increases were partially offset by volumetric bill credits MGU is required to provide customers under a MPUC order addressing the effects of the Tax Legislation to return tax savings from the ruling. See Note 15, Income Taxes, and Note 25, Regulatory Environment, for more information.

Operating Income

Operating income at the other states segment decreased $3.5 million during 2019, compared with 2018. The decrease was driven by a $6.6 million increase in operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes) partially offset by the increase in margins discussed above. The increase in operating expenses was partially driven by lower property and revenue taxes in 2018 resulting from a favorable judgment that MERC received related to a property tax matter. Because property taxes were under-recovered from rate payers in prior years, MERC received $4.8 million of the judgment, with the remaining amount being passed back to customers through the property tax tracker. The increase was also driven by a $2.1 million positive impact on 2018 depreciation and amortization expense from a depreciation study approved by the MPUC in the second quarter of 2018. These rates were effective retroactively to January 2017.

Non-Utility Energy Infrastructure Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Operating income	**$ 366.6**	$ 365.8	$ 0.8

2019 Compared with 2018

Operating income at the non-utility energy infrastructure segment increased $0.8 million during 2019, compared with 2018. Operating income at We Power increased $4.8 million, driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE. Higher operating income at We Power was partially offset by operating losses at the Upstream and Bishop Hill III wind generation facilities. The majority of earnings from our ownership interests in wind generation facilities come in the form of wind production tax credits, and are recognized as an offset to income tax expense. For more information on Upstream and Bishop Hill III, see Note 2, Acquisitions.

Corporate and Other Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Operating loss	**$ (34.4)**	$ (22.2)	$ (12.2)

2019 Compared with 2018

The operating loss at the corporate and other segment increased $12.2 million during 2019, compared with 2018, primarily driven by the transfer of assets from WBS, our centralized services company, to our regulated utilities in 2018. As a result of these transfers, the return on these assets is now recognized within our regulated utility operations. Also contributing to the increase in operating loss was a gain recorded in the third quarter of 2018 that related to a previous sale of a legacy business.

Electric Transmission Segment Operations

	Year Ended December 31		
(in millions)	**2019**	**2018**	**B (W)**
Equity in earnings of transmission affiliates	**$ 127.6**	$ 136.7	$ (9.1)

2019 Compared with 2018

Earnings from our electric transmission segment operations, primarily related to our investment in ATC, decreased $9.1 million during 2019, compared with 2018. A $19.3 million decrease in ATC's earnings was the result of a FERC order issued in November 2019 that addressed complaints related to ATC's allowed ROE. Increased earnings from continued capital investment partially offset the negative impact from the FERC order.

Consolidated Other Income, Net

(in millions)	Year Ended December 31 2019	2018	B (W)
AFUDC – Equity	**$ 14.4**	$ 15.2	$ (0.8)
Non-service components of net periodic benefit costs	**36.2**	26.0	10.2
Gains (losses) from investments held in rabbi trust	**21.2**	(1.8)	23.0
Other, net	**30.4**	30.9	(0.5)
Other income, net	**$ 102.2**	$ 70.3	$ 31.9

2019 Compared with 2018

Other income, net increased $31.9 million during 2019, compared with 2018. An increase of $23.0 million was due to net gains from investments held in the Integrys rabbi trust during 2019, compared with net losses during 2018. These investment gains partially offset benefits costs related to deferred compensation, which are included in other operation and maintenance expense. See Note 16, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust. Also contributing to the increase was $10.2 million of higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 19, Employee Benefits, for more information on our benefit costs.

Consolidated Interest Expense

(in millions)	Year Ended December 31 2019	2018	B(W)
Interest expense	**$ 501.5**	$ 445.1	$ (56.4)

2019 Compared with 2018

Interest expense increased $56.4 million during 2019, compared with 2018. The increase was primarily due to higher long-term debt balances. This increase in debt balances was primarily related to continued capital investments.

Consolidated Income Tax Expense

	Year Ended December 31 2019	2018	B (W)
Effective tax rate	**9.9%**	13.8%	3.9%

2019 Compared with 2018

Our effective tax rate was 9.9% in 2019, compared to 13.8% in 2018. The 3.9% decrease in the effective tax rate was primarily due to an increase in wind production tax credits related to acquisitions of ownership interests in wind generation facilities in our non-utility energy infrastructure segment, the impact of the 2018 PSCW order regarding the benefits associated with the Tax Legislation, and the increased benefit from the flow through of tax repairs in connection with the 2017 Wisconsin rate settlement. The impacts from the 2018 PSCW order related to the Tax Legislation and the flow through of tax repairs were offset in operating income at the Wisconsin segment. See Note 2, Acquisitions, Note 15, Income Taxes, and Note 25, Regulatory Environment, for more information.

We expect our 2020 annual effective tax rate to be between 16% and 17%, which includes an estimated 4% effective tax rate benefit due to the amortization of unprotected excess deferred taxes in connection with the 2019 Wisconsin rate orders. Excluding this estimated effective tax rate benefit, the expected 2020 range would be between 20% and 21%.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion and analysis of our Liquidity and Capital Resources includes comparisons of our cash flows for the year ended December 31, 2019 with the year ended December 31, 2018. For a similar discussion that compares our cash flows for the year ended December 31, 2018 with the year ended December 31, 2017, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources in Part II of our 2018 Annual Report on Form 10-K.

Cash Flows

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

(in millions)	2019	2018	Change in 2019 Over 2018
Cash provided by (used in):			
Operating activities	**$ 2,345.5**	$ 2,445.5	$ (100.0)
Investing activities	**(2,494.9)**	(2,384.4)	(110.5)
Financing activities	**85.6**	26.4	59.2

Operating Activities

2019 Compared with 2018

Net cash provided by operating activities decreased $100.0 million during 2019, compared with 2018, driven by:

- A $116.0 million decrease in cash due to higher collateral requirements in 2019, compared with 2018, driven by funding for both open natural gas contracts and settled natural gas contracts. See Note 17, Derivative Instruments, for more information.

- A $44.4 million decrease in cash due to an increase in payments for interest related to higher long-term debt balances during 2019, compared with 2018.

- A $40.5 million decrease in cash from higher payments for other operation and maintenance expense. During 2019, our payments were higher for transmission, benefits, and storm restoration, compared with 2018.

- A $25.6 million decrease in cash related to higher payments for environmental remediation from work completed on former manufactured gas plant sites during 2019, compared with 2018.

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

- A $74.0 million increase in cash primarily related to lower payments for natural gas and for fuel and purchased power. Lower payments for natural gas were due to a 14.5% decrease in the average per-unit cost of natural gas sold during 2019, compared with 2018. Lower payments for fuel and purchased power were due to the retirements of the Pleasant Prairie power plant in April 2018, Edgewater Unit 4 in September 2018, Pulliam Units 7 and 8 in October 2018, and the PIPP in March 2019.

- A $41.2 million net increase in cash related to $24.9 million of cash received for income taxes during 2019, compared with $16.3 million of cash paid for income taxes during 2018. This increase in cash was primarily due to alternative minimum tax credits that were refunded to us during 2019.

- An $11.7 million increase in cash related to a decrease in contributions and payments related to pension and OPEB plans during 2019, compared with 2018.

Investing Activities

2019 Compared with 2018

Net cash used in investing activities increased $110.5 million during 2019, compared with 2018, driven by:

- The acquisition of an 80% ownership interest in Upstream in January 2019 for $268.2 million, which is net of cash and restricted cash acquired of $9.2 million. See Note 2, Acquisitions, for more information.

- A $145.1 million increase in cash paid for capital expenditures during 2019, compared with 2018, which is discussed in more detail below.

- A $53.4 million net decrease in restricted cash during 2019, compared with 2018, due to a $118.4 million decrease in the proceeds received from the sale of investments held in the Integrys rabbi trust, partially offset by a $65.0 million decrease in the purchase of investments held in the rabbi trust.

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

- The acquisition of Bishop Hill III during 2018 for $162.9 million, which is net of restricted cash acquired of $4.5 million. See Note 2, Acquisitions, for more information.

- The acquisition of Forward Wind Energy Center in April 2018 for $77.1 million. See Note 2, Acquisitions, for more information.

- The acquisition of an 80% ownership interest in Coyote Ridge during December 2018 for $61.4 million. See Note 2, Acquisitions, for more information.

- A $32.4 million increase in cash related to a reimbursement received from ATC for construction costs during 2019. See Note 20, Investment in Transmission Affiliates, for more information.

- A $25.5 million increase in proceeds received from the sale of assets and businesses, primarily related to the sale of four PDL solar power generation facilities during 2019, compared with 2018. See Note 3, Dispositions, for more information.

Capital Expenditures

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

Reportable Segment *(in millions)*	**2019**	**2018**	**Change in 2019 Over 2018**
Wisconsin	**$ 1,378.6**	$ 1,389.0	$ (10.4)
Illinois	**624.9**	547.1	77.8
Other states	**109.1**	103.6	5.5
Non-utility energy infrastructure	**121.7**	36.3	85.4
Corporate and other	**26.5**	39.7	(13.2)
Total capital expenditures	**$ 2,260.8**	$ 2,115.7	$ 145.1

2019 Compared with 2018

The decrease in cash paid for capital expenditures at the Wisconsin segment during 2019, compared with 2018, was primarily driven by the construction of the new natural gas-fired generation facility in the Upper Peninsula of Michigan, projects at the OCPP, the implementation of an ERP system, our AMI program and various other software projects, a natural gas lateral project at WPS's Fox Energy Center, and upgrades to WE's electric distribution system during 2018. These decreases in cash paid for capital expenditures were partially offset by increased capital expenditures related to WPS's Two Creeks project, upgrades to WPS's natural gas distribution system, and an information technology project created to improve WE's and WG's billing, call center, and credit collection functions during 2019.

The increase in cash paid for capital expenditures at the Illinois segment during 2019, compared with 2018, was driven by an increase in facilities projects at PGL, partially offset by a decrease in AMI expenditures at NSG during 2019.

The increase in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2019, compared with 2018, was primarily driven by the construction of Coyote Ridge. See Note 2, Acquisitions, for more information.

The decrease in cash paid for capital expenditures at the corporate and other segment during 2019, compared with 2018, was primarily driven by the implementation of a new ERP system during the first quarter of 2018.

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

Financing Activities

2019 Compared with 2018

Net cash provided by financing activities increased $59.2 million during 2019, compared with 2018, driven by:

- A $593.2 million increase in cash related to lower long-term debt repayments during 2019, compared with 2018.
- A $155.0 million increase in cash due to higher issuances of long-term debt during 2019, compared with 2018.
- A $37.9 million increase in cash from stock options exercised during 2019, compared with 2018.

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

- A $604.8 million decrease in cash related to higher net repayments of commercial paper during 2019, compared with 2018.
- A $67.7 million decrease in cash due to an increase in the number and cost of shares of our common stock purchased during 2019, compared with 2018, to satisfy requirements of our stock-based compensation plans.
- A $47.2 million decrease in cash due to higher dividends paid on our common stock during 2019, compared with 2018. In January 2019, our Board of Directors increased our quarterly dividend by $0.0375 per share (6.8%) effective with the first quarter of 2019 dividend payment.

Significant Financing Activities

For more information on our financing activities, see Note 12, Short-Term Debt and Lines of Credit, and Note 13, Long-Term Debt.

Capital Resources and Requirements

Capital Resources

Liquidity

We anticipate meeting our capital requirements for our existing operations through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors.

We currently have access to the capital markets and have been able to generate funds both internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets, and internally generated cash.

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. See Note 12, Short-Term Debt and Lines of Credit, for more information about these credit facilities.

The following table shows our capitalization structure as of December 31, 2019 and 2018, 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:

	2019		2018	
(in millions)	**Actual**	**Adjusted**	**Actual**	**Adjusted**
Common shareholders' equity	**$ 10,113.4**	**$ 10,363.4**	$ 9,788.9	$ 10,038.9
Preferred stock of subsidiary	**30.4**	**30.4**	30.4	30.4
Long-term debt (including current portion)	**11,904.2**	**11,654.2**	10,359.0	10,109.0
Short-term debt	**830.8**	**830.8**	1,440.1	1,440.1
Total capitalization	**$ 22,878.8**	**$ 22,878.8**	$ 21,618.4	$ 21,618.4
Total debt	**$ 12,735.0**	**$ 12,485.0**	$ 11,799.1	$ 11,549.1
Ratio of debt to total capitalization	**55.7%**	**54.6%**	54.6%	53.4%

Included in long-term debt on our balance sheets as of December 31, 2019 and 2018, is $500.0 million principal amount of 2007 Junior Notes. The adjusted presentation attributes $250.0 million of the 2007 Junior Notes to common 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.

For a summary of the interest rates, maturity, and amounts of long-term debt outstanding on a consolidated basis, see Note 13, Long-Term Debt.

As described in Note 10, Common Equity, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

At December 31, 2019, 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 12, Short-Term Debt and Lines of Credit, and Note 13, Long-Term Debt, for more information.

Working Capital

As of December 31, 2019, our current liabilities exceeded our current assets by $1,089.1 million. We do not expect this to have any impact on our liquidity since we believe we have adequate back-up lines of credit in place for our ongoing operations. We also believe that we can access the capital markets to finance our construction programs and to refinance current maturities of long-term debt, if necessary.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, we have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at S&P Global Ratings and/or Baa3 at Moody's Investors Service. 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 November 2019, Moody's downgraded the ratings of WG senior unsecured debt to A3 from A2 and WG commercial paper to P-2 from P-1. The change in ratings has not had, and we do not believe that it will have, a material impact on our ability to access capital. Moody's changed the rating outlook for WG to stable from negative.

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.

If we are unable to successfully take actions to manage any additional adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments or technical corrections exacerbate the adverse impacts of the Tax Legislation, the legislation could result in credit rating agencies placing our or our subsidiaries' credit ratings on negative outlook or additional downgrading of our or our subsidiaries' credit ratings. Any such actions by credit rating agencies may make it more difficult and costly for us and our subsidiaries to issue future debt securities and certain other types of financing and could increase borrowing costs under our and our subsidiaries' credit facilities.

Capital Requirements

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2019:

	Payments Due by Period (1)				
(in millions)	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-term debt obligations (2)	$ 20,753.7	$ 1,170.2	$ 2,595.1	$ 1,426.1	$ 15,562.3
Finance lease obligations (3)	102.7	9.3	15.4	1.8	76.2
Operating lease obligations (4)	56.2	6.8	9.6	9.7	30.1
Energy and transportation purchase obligations (5)	11,570.0	1,231.1	2,152.9	1,667.5	6,518.5
Purchase orders (6)	886.0	463.3	250.2	85.1	87.4
Pension and OPEB funding obligations (7)	39.6	12.5	27.1	—	—
Total contractual obligations	$ 33,408.2	$ 2,893.2	$ 5,050.3	$ 3,190.2	$ 22,274.5

(1) The amounts included in the table are calculated using current market prices, forward curves, and other estimates.

(2) Principal and interest payments on long-term debt (excluding finance lease obligations). The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2019.

(3) Finance lease obligations for power purchase commitments and land leases related to solar projects. This amount does not include We Power leases to WE which are eliminated upon consolidation. See Note 14, Leases, for more information.

(4) Operating lease obligations for office space, land, and rail car leases. See Note 14, Leases, for more information.

(5) Energy and transportation purchase obligations under various contracts for the procurement of fuel, power, gas supply, and associated transportation related to utility and non-utility operations.

(6) Purchase obligations related to normal business operations, information technology, and other services. Also includes construction obligations related to Two Creeks and Badger Hollow I.

(7) Obligations for pension and OPEB plans cannot reasonably be estimated beyond 2022.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note 15, Income Taxes.

The table above also does not reflect estimated future payments related to the manufactured gas plant remediation liability of $589.2 million at December 31, 2019, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 23, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $483.5 million are not included in the above table. Settlement of these liabilities cannot be determined with certainty, but we believe the majority of these liabilities will be settled in more than five years. See Note 8, Asset Retirement Obligations, for more information.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

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, impacts from the Tax Legislation, additional changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends. Our estimated capital expenditures and acquisitions for the next three years are as follows:

(in millions)	2020	2021	2022
Wisconsin	$ 1,482.0	$ 1,881.1	$ 1,630.5
Illinois	779.0	619.4	586.7
Other states	117.4	111.6	87.4
Non-utility energy infrastructure	852.5	159.7	393.0
Corporate and other	24.6	22.7	2.7
Total	$ 3,255.5	$ 2,794.5	$ 2,700.3

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. WPS is also continuing work on the System Modernization and Reliability Project. This project includes modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WPS expects to invest approximately $100 million between 2020 and 2022 on this project.

As part of our commitment to invest in zero-carbon generation, we have either filed for or received approval to invest in 300 MW of utility-scale solar within our Wisconsin segment. WPS has partnered with an unaffiliated utility to construct two solar projects in Wisconsin. Badger Hollow I is located in Iowa County, Wisconsin, and Two Creeks is located in Manitowoc County, Wisconsin. Once constructed, WPS will own 100 MW of the output of each project for a total of 200 MW. WPS's share of the cost of both projects is estimated to be $256 million. Construction began at Two Creeks and Badger Hollow I in August 2019 and October 2019, respectively. Commercial operation of both projects is targeted for the end of 2020. WE has partnered with an unaffiliated utility to acquire an ownership interest in a proposed solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin. At its meeting on February 20, 2020, the PSCW approved the acquisition of this project. The approval is still subject to WE's receipt and review of a final written order from the PSCW. Once constructed, WE will own 100 MW of the output 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 end of 2021. Solar generation technology has greatly improved, has become more cost-effective, and it complements our summer demand curve.

WE and WG each plan to construct their own LNG facility. Subject to PSCW approval, each facility would provide approximately one billion cubic feet 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 LNG facilities is targeted for the end of 2023.

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 2022 is between $280 million and $300 million. See Note 25, 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 Blooming Grove. 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 $90 million from 2020 through 2022. We do not expect to make any contributions to ATC Holdco during that period.

Common Stock Matters

For information related to our common stock matters, see Note 10, Common Equity.

On January 16, 2020, our Board of Directors increased our quarterly dividend to $0.6325 per share effective with the first quarter of 2020 dividend payment, an increase of 7.2%. This equates to an annual dividend of $2.53 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.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $3.9 billion as of December 31, 2019. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $65.9 million and $77.6 million to our pension and OPEB plans in 2019 and 2018, respectively. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note 19, Employee Benefits.

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 12, Short-Term Debt and Lines of Credit, Note 18, Guarantees, and Note 22, Variable Interest Entities.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

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:

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 specific orders or by a generic order 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. In general, our regulatory assets are recovered over a period of between one to twenty years. 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, 2019, our regulatory assets were $3,527.6 million, and our regulatory liabilities were $4,080.4 million.

Due to the Tax Legislation, our regulated utilities remeasured their deferred taxes and recorded a tax benefit of $2,529 million. Our utilities have been returning this tax benefit to ratepayers through refunds, bill credits, riders, and reductions to other regulatory assets, which we expect to continue. See Note 15, Income Taxes, and Note 25, Regulatory Environment, for more information.

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, 2019, we had not received any significant disallowances of the costs incurred for this project. WPS received approval to recover these costs in the rate order it received from the PSCW in December 2019. See Note 25, Regulatory Environment, for more information.

- 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 2019, PGL filed its 2018 reconciliation with the ICC, which, along with the 2017 and 2016 reconciliations, are still pending. In July 2019, the ICC approved a settlement of the 2015 reconciliation, which includes a rate base reduction of $7.0 million and a $7.3 million refund to ratepayers. As of December 31, 2019, all amounts had been refunded to customers. As of December 31, 2019, 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 25, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

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 1(d), Operating Revenues, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our utilities' service territories during 2019 and 2018, as measured by degree days, may 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, 2019, and December 31, 2018, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $10.8 million and $16.9 million in 2019 and 2018, 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, 2019	Expected Return on Assets in 2020
Pension trust funds	**$ 3,007.0**	6.87%
OPEB trust funds	**$ 879.6**	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

We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, and regulatory and environmental compliance in order to minimize its effects in future years through pricing strategies, productivity improvements, and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

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.

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. It is uncertain when, if at all, retail choice might be implemented in Wisconsin. However, Michigan has adopted a limited retail choice program.

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.

Michigan

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, 2019, Michigan law limited customer choice to 10% of an electric utility's Michigan retail load, but this cap could potentially be reduced in future years due to the December 2016 passage of Michigan Act 341. Based on current law, our iron ore mine customer, Tilden, is exempt from the 10% cap. 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 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 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 rates 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 customers (formerly WPS's Michigan 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.

Environmental Matters

See Note 23, 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.

Other Matters

Tax Cuts and Jobs Act of 2017

In December 2017, the Tax Legislation was signed into law. In 2018 and 2019, the PSCW and the MPSC issued written orders regarding how to refund certain tax savings from the Tax Legislation to our ratepayers in Wisconsin and Michigan, respectively. The various remaining impacts of the Tax Legislation on our Wisconsin operations were addressed in our recent rate orders issued by the PSCW in December 2019. In addition, the ICC approved the VITA in Illinois during April 2018, and, in Minnesota, the MPUC included the various impacts of the Tax Legislation in MERC's final 2018 rate order.

In July 2019, the FERC approved WPS's revised formula rate tariff, which incorporated the impacts of the Tax Legislation. We are also working with the FERC to modify WE's formula rate tariff for the impacts of the Tax Legislation, and we expect to receive FERC approval for WE's modified tariff in 2020. See Note 25, Regulatory Environment, for more information.

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 has 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 will reduce the base ROE that ATC is allowed to collect on a going-forward basis, as discussed below. Various parties have requested a rehearing by the FERC of the November 2019 Order in its entirety.

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%, as well as the 0.5% incentive adder approved by the FERC in January 2015 for MISO transmission owners. 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 the 0.5% ROE incentive adder, which only applies to revenues collected after January 6, 2015. In addition, 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 21, 2019. As a result, ATC will provide WE and WPS with refunds related to the transmission costs they paid during the two refund periods, and these refunds will be 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 0.5% incentive adder were reasonable for the period covered by the second complaint, February 12, 2015 through May 10, 2016. However, in its 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. Refunds could still be required, however, for the second complaint period depending on the outcome of numerous rehearing requests filed with the FERC. Therefore, our financials continue to reflect a liability of $41.9 million resulting in reduced equity earnings from ATC. This liability reflects a 10.38% 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.

Bonus Depreciation Provisions

Bonus depreciation is an additional amount of first-year tax deductible depreciation that is awarded above what would normally be available. The bonus depreciation deduction available for public utility property subject to rate-making by a government entity or public utility commission was modified by the Tax Legislation. Based on the provisions of the Tax Legislation, bonus depreciation can no longer be deducted for public utility property acquired and placed in service after December 31, 2017. The provisions of the Tax Legislation regarding the repeal of bonus depreciation do not apply to some of our non-utility investments.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgments.

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, 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, 2019, we had $3,527.6 million in regulatory assets and $4,080.4 million in regulatory liabilities. See Note 5, 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, 2019. 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 each 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.

Our reporting units had the following goodwill balances at July 1, 2019:

(in millions, except percentages)	**Goodwill**	**Percentage of Total Goodwill**
Wisconsin	$ 2,104.3	68.9%
Illinois	758.7	24.9%
Other states	183.2	6.0%
Bluewater	6.6	0.2%
Total goodwill	$ 3,052.8	100.0%

See Note 9, Goodwill, 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, adverse legal factors or a change in business climate, operating or cash flow losses, or an expectation that the asset might be sold. These assessments require significant assumptions and judgments by management. Long-lived assets that would be subject to an impairment assessment would 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, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

In accordance with ASC 980-360, 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. As a result, the remaining net book value of these assets can be significant. If a generating unit meets 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 or 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.

Pleasant Prairie power plant, Pulliam Units 7 and 8, and the jointly-owned Edgewater 4 generating unit were retired during 2018. PIPP was retired during 2019. Effective with the rate orders issued by the PSCW in December 2019, WE and WPS received approval to collect a return of and on the entire net book value of the retired generating units, excluding Pleasant Prairie power plant. WE will collect a full return of and on all but $100 million of the net book value of the Pleasant Prairie power plant. In accordance with its PSCW rate order received in December 2019, WE will seek a financing order from the PSCW to securitize the remaining $100 million. See Note 6, Property, Plant, and Equipment, and Note 25, 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 19, 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 ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2019 Pension Cost**
Discount rate	(0.5)	$ 206.6	$ 17.4
Discount rate	0.5	(178.2)	(10.6)
Rate of return on plan assets	(0.5)	N/A	13.3
Rate of return on plan assets	0.5	N/A	(13.3)

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 2019 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 35.3	$ 3.8
Discount rate	0.5	(30.6)	(3.8)
Health care cost trend rate	(0.5)	(18.6)	(4.5)
Health care cost trend rate	0.5	21.3	5.1
Rate of return on plan assets	(0.5)	N/A	3.8
Rate of return on plan assets	0.5	N/A	(3.8)

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 7.12% in 2019 and 2018, and 7.11% in 2017. The actual rate of return on pension plan assets, net of fees, was 18.89%, (4.30)%, and 13.74%, in 2019, 2018, and 2017, 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 19, 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. This unbilled revenue is 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. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2019 of approximately $7.4 billion included accrued utility revenues of $478.8 million as of December 31, 2019.

Income Tax Expense

We are required to estimate income taxes for each of the jurisdictions in which we operate 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 and the outcomes of tax audits and appeals 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.

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(o), Income Taxes, and Note 15, Income Taxes, for a discussion of accounting for income taxes.

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(p), Fair Value Measurements, Note 1(q), Derivative Instruments, and Note 18, 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, 2019 and 2018, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 27, 2020, 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 audits 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 5 and 25 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 $3,528 million and $4,080 million of regulatory assets and liabilities, respectively, as of December 31, 2019.

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 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 precedence of the Commissions' treatment of similar costs under similar circumstances.

- 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 27, 2020

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, 2019, 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, 2019, 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, 2019, of the Company and our report dated February 27, 2020, 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 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 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 27, 2020

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions, except per share amounts)*	2019	2018	2017
Operating revenues	**$ 7,523.1**	$ 7,679.5	$ 7,648.5
Operating expenses			
Cost of sales	**2,678.8**	2,897.9	2,822.8
Other operation and maintenance	**2,184.8**	2,270.5	2,056.1
Depreciation and amortization	**926.3**	845.8	798.6
Property and revenue taxes	**201.8**	196.9	194.9
Total operating expenses	**5,991.7**	6,211.1	5,872.4
Operating income	**1,531.4**	1,468.4	1,776.1
Equity in earnings of transmission affiliates	**127.6**	136.7	154.3
Other income, net	**102.2**	70.3	73.7
Interest expense	**501.5**	445.1	415.7
Other expense	**(271.7)**	(238.1)	(187.7)
Income before income taxes	**1,259.7**	1,230.3	1,588.4
Income tax expense	**125.0**	169.8	383.5
Net income	**1,134.7**	1,060.5	1,204.9
Preferred stock dividends of subsidiary	**1.2**	1.2	1.2
Net loss attributed to noncontrolling interests	**0.5**	—	—
Net income attributed to common shareholders	**$ 1,134.0**	$ 1,059.3	$ 1,203.7
Earnings per share			
Basic	**$ 3.60**	$ 3.36	$ 3.81
Diluted	**$ 3.58**	$ 3.34	$ 3.79
Weighted average common shares outstanding			
Basic	**315.4**	315.5	315.6
Diluted	**316.7**	316.9	317.2

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

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2019	2018	2017
Net income	**$ 1,134.7**	$ 1,060.5	$ 1,204.9
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Net derivative losses, net of tax benefits of $1.3, $0.8, and $0.0, respectively	**(3.5)**	(2.1)	—
Reclassification of net gains to net income, net of tax	**(0.8)**	(1.2)	(1.3)
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	1.6	—
Cash flow hedges, net	**(4.3)**	(1.7)	(1.3)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax expense (benefit) of $1.0, $(1.2), and $0.6, respectively	**2.6**	(3.1)	0.9
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.2**	0.3	0.4
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	(1.0)	—
Defined benefit plans, net	**2.8**	(3.8)	1.3
Other comprehensive loss, net of tax	**(1.5)**	(5.5)	—
Comprehensive income	**1,133.2**	1,055.0	1,204.9
Preferred stock dividends of subsidiary	**1.2**	1.2	1.2
Comprehensive loss attributed to noncontrolling interests	**0.5**	—	—
Comprehensive income attributed to common shareholders	**$ 1,132.5**	$ 1,053.8	$ 1,203.7

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

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D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2019	2018
Assets		
Current assets		
Cash and cash equivalents	**$ 37.5**	$ 84.5
Accounts receivable and unbilled revenues, net of reserves of $140.0 and $149.2, respectively	**1,176.5**	1,280.9
Materials, supplies, and inventories	**549.8**	548.2
Prepayments	**261.8**	256.8
Other	**68.0**	77.2
Current assets	**2,093.6**	2,247.6
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $8,878.7 and $8,636.6, respectively	**23,620.1**	22,000.9
Regulatory assets	**3,506.7**	3,805.1
Equity investment in transmission affiliates	**1,720.8**	1,665.3
Goodwill	**3,052.8**	3,052.8
Other	**957.8**	704.1
Long-term assets	**32,858.2**	31,228.2
Total assets	**$ 34,951.8**	$ 33,475.8
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 830.8**	$ 1,440.1
Current portion of long-term debt	**693.2**	365.0
Accounts payable	**908.1**	876.4
Accrued payroll and benefits	**199.8**	185.4
Other	**550.8**	464.8
Current liabilities	**3,182.7**	3,331.7
Long-term liabilities		
Long-term debt	**11,211.0**	9,994.0
Deferred income taxes	**3,769.3**	3,388.1
Deferred revenue, net	**497.1**	520.4
Regulatory liabilities	**3,992.8**	4,251.6
Environmental remediation liabilities	**589.2**	616.4
Pension and OPEB obligations	**326.2**	422.8
Other	**1,128.9**	1,108.1
Long-term liabilities	**21,514.5**	20,301.4
Commitments and contingencies (Note 23)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,434,531 and 315,523,192 shares outstanding, respectively	**3.2**	3.2
Additional paid in capital	**4,186.6**	4,250.1
Retained earnings	**5,927.7**	5,538.2
Accumulated other comprehensive loss	**(4.1)**	(2.6)
Common shareholders' equity	**10,113.4**	9,788.9
Preferred stock of subsidiary	**30.4**	30.4
Noncontrolling interests	**110.8**	23.4

Total liabilities and equity	**$ 34,951.8**	$ 33,475.8

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

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E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2019	2018	2017
Operating activities			
Net income	**$ 1,134.7**	$ 1,060.5	$ 1,204.9
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**926.3**	845.8	798.6
Deferred income taxes and investment tax credits, net	**162.9**	297.3	271.7
Contributions and payments related to pension and OPEB plans	**(65.9)**	(77.6)	(120.5)
Equity income in transmission affiliates, net of distributions	**(2.9)**	(18.6)	(4.8)
Change in –			
Accounts receivable and unbilled revenues	**98.2**	23.5	(86.4)
Materials, supplies, and inventories	**(1.5)**	(8.8)	49.3
Other current assets	**(7.1)**	(10.0)	(7.1)
Accounts payable	**1.5**	110.6	8.5
Other current liabilities	**78.7**	(67.6)	161.8
Other, net	**20.6**	290.4	(197.4)
Net cash provided by operating activities	**2,345.5**	2,445.5	2,078.6
Investing activities			
Capital expenditures	**(2,260.8)**	(2,115.7)	(1,959.5)
Acquisition of Upstream, net of cash and restricted cash acquired of $9.2	**(268.2)**	—	—
Acquisition of Bishop Hill III, net of restricted cash acquired of $4.5	**—**	(162.9)	—
Acquisition of Forward Wind Energy Center	**—**	(77.1)	—
Acquisition of Coyote Ridge	**—**	(61.4)	—
Acquisition of Bluewater	**—**	—	(226.0)
Capital contributions to transmission affiliates	**(52.6)**	(53.5)	(109.6)
Proceeds from the sale of assets and businesses	**37.6**	12.1	24.0
Proceeds from the sale of investments held in rabbi trust	**0.2**	118.6	8.7
Purchase of investments held in rabbi trust	**—**	(65.0)	(3.7)
Reimbursement for ATC's construction costs	**32.4**	—	—
Other, net	**16.5**	20.5	12.0
Net cash used in investing activities	**(2,494.9)**	(2,384.4)	(2,254.1)
Financing activities			
Exercise of stock options	**67.0**	29.1	30.8
Purchase of common stock	**(140.1)**	(72.4)	(71.3)
Dividends paid on common stock	**(744.5)**	(697.3)	(656.5)
Issuance of long-term debt	**1,895.0**	1,740.0	435.0
Retirement of long-term debt	**(360.1)**	(953.3)	(154.5)
Change in short-term debt	**(609.3)**	(4.5)	584.4
Other, net	**(22.4)**	(15.2)	(6.5)
Net cash provided by financing activities	**85.6**	26.4	161.4
Net change in cash, cash equivalents, and restricted cash	**(63.8)**	87.5	(14.1)
Cash, cash equivalents, and restricted cash at beginning of year	**146.1**	58.6	72.7
Cash, cash equivalents, and restricted cash at end of year	**$ 82.3**	$ 146.1	$ 58.6

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, 2016	$ 3.2	$ 4,309.8	$ 4,613.9	$ 2.9	$ 8,929.8	$ 30.4	$ —	$ 8,960.2
Net income attributed to common shareholders	—	—	1,203.7	—	1,203.7	—	—	1,203.7
Common stock dividends of $2.08 per share	—	—	(656.5)	—	(656.5)	—	—	(656.5)
Exercise of stock options	—	30.8	—	—	30.8	—	—	30.8
Purchase of common stock	—	(71.3)	—	—	(71.3)	—	—	(71.3)
Cumulative effect adjustment from ASU 2016-09 adoption	—	—	15.7	—	15.7	—	—	15.7
Stock-based compensation and other	—	9.2	—	—	9.2	—	—	9.2
Balance at December 31, 2017	$ 3.2	$ 4,278.5	$ 5,176.8	$ 2.9	$ 9,461.4	$ 30.4	$ —	$ 9,491.8
Net income attributed to common shareholders	—	—	1,059.3	—	1,059.3	—	—	1,059.3
Other comprehensive loss	—	—	—	(6.1)	(6.1)	—	—	(6.1)
Common stock dividends of $2.21 per share	—	—	(697.3)	—	(697.3)	—	—	(697.3)
Exercise of stock options	—	29.1	—	—	29.1	—	—	29.1
Purchase of common stock	—	(72.4)	—	—	(72.4)	—	—	(72.4)
Cumulative effect adjustment from ASU 2018-02 adoption	—	—	(0.6)	0.6	—	—	—	—
Acquisition of noncontrolling interests	—	—	—	—	—	—	23.8	23.8
Stock-based compensation and other	—	14.9	—	—	14.9	—	(0.4)	14.5
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**

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 2.9 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 and 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, 2019 related to the minority interests at Bishop Hill III, Coyote Ridge, and Upstream 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 Bluewater and 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, Bostco, Wisvest, WECC, WBS, and PDL. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. In 2019, we sold certain PDL solar power generating facilities. See Note 3, Dispositions, for more information on these sales.

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 7, 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 that exceed a 2% price variance from the costs included in the rates charged to customers. Our electric utilities monitor the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW. In contrast, the rates of our Michigan retail electric customers include recovery of fuel and purchased power costs on a one-for-one basis. In addition, the Wisconsin residential tariffs of WE and WPS include a mechanism for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.

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

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

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

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

Natural Gas Utility Operating Revenues

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

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

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year. In addition, the rates of PGL and NSG, and the residential tariffs of WE, WPS, and WG, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of both environmental cleanup costs, energy conservation and management program costs, and income tax expense changes resulting from the Tax Legislation. Finally, PGL's rates include a cost recovery mechanism for SMP costs, and similarly, MERC's rates include a rider to recover costs incurred to replace or modify natural gas facilities.

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

Other Natural Gas Operating Revenues

We have other natural gas operating revenues from Bluewater, which is in our non-utility energy infrastructure segment. Bluewater has entered into long-term service agreements for natural gas storage services with WE, WPS, and WG, and provides service to several unaffiliated customers. All amounts associated with services from affiliates have been eliminated at the consolidated level.

Other Non-Utility Operating Revenues

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 deferred revenue, and we continually amortize the deferred carrying costs to revenues over the life of the related lease term that We Power has with WE. During 2019 and 2018, we recorded $25.4 million and $25.3 million, respectively, of revenue related to these deferred carrying costs, which were included in the contract liability balance at the beginning of the period. This contract liability is presented as deferred revenue, net on our balance sheets.

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.

Revenues from distributed renewable solar projects consist primarily of sales of renewable energy and SRECs generated by PDL. The sale of SRECs is a distinct performance obligation as they are often sold separately from the renewable energy generated. Although the performance obligation for the sale of renewable energy is recognized over time and the performance obligation for SRECs is recognized at a point-in-time, the timing of revenue recognition is the same, as the generation of renewable energy and sales of SREC's occur concurrently. See Note 3, Dispositions, for more information on the sale of certain of these solar facilities.

Wind generation revenues from WECI's ownership interests in wind generation facilities continued to grow with the acquisition of Upstream in January 2019. See Note 2, Acquisitions, for more information on Upstream, the December 2018 acquisition of Coyote Ridge, and other planned future 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. The contracts consist of one distinct performance obligation satisfied over time, as the electricity is delivered and consumed by the customer simultaneously. We recognize revenue as energy is produced and delivered to the customer within the production month. Upstream's revenue is substantially fixed over 10 years through an agreement with an unaffiliated third party.

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 25, 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) Materials, Supplies, and Inventories—Our inventory as of December 31 consisted of:

(in millions)	2019	2018
Materials and supplies	**$ 234.2**	$ 226.6
Natural gas in storage	**227.7**	232.9
Fossil fuel	**87.9**	88.7
Total	**$ 549.8**	$ 548.2

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 19% and 16% of total inventories at December 31, 2019 and 2018, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2019 and 2018, exceeded the LIFO cost by $9.8 million and $72.4 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $1.95 at December 31, 2019, and $3.08 at December 31, 2018.

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

(f) 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 5, Regulatory Assets and Liabilities, for more information.

(g) 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	**2019**	**2018**	**2017**
WE	**3.11%**	3.18%	2.95%
WPS	**2.44%**	2.50%	2.55%
WG	**2.29%**	2.30%	2.30%
PGL	**3.20%**	3.25%	3.29%
NSG	**2.48%**	2.45%	2.43%
MERC *	**2.33%**	1.95%	2.51%
MGU	**2.54%**	2.61%	2.61%
UMERC	**2.87%**	2.50%	2.46%

* The 2018 rate reflects the impact of a new depreciation study approved by the MPUC in May 2018. The rates approved were effective retroactive to January 2017. An approximate $1.4 million reduction in depreciation expense was recorded in 2018 related to this depreciation study.

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 6, Property, Plant, and Equipment, for more information.

(h) 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 other utilities' AFUDC rates are determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities did not record significant AFUDC for 2019, 2018, or 2017. Average AFUDC rates are shown below:

	2019	
	Average AFUDC Retail Rate	**Average AFUDC Wholesale Rate**
WE	**8.45%**	**5.11%**
WPS	**7.72%**	**2.58%**
WG	**8.33%**	**N/A**
UMERC	**6.28%**	**N/A**
WBS	**7.72%**	**N/A**

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

(in millions)	**2019**	**2018**	**2017**
AFUDC – Debt			
WE	**$ 1.5**	$ 1.5	$ 1.2
WPS	**2.4**	1.9	1.6
WG	**0.5**	0.2	0.3
UMERC	**1.3**	2.4	0.1
WBS	**0.1**	0.2	1.1
Other	**0.1**	0.7	0.6
Total AFUDC – Debt	**$ 5.9**	$ 6.9	$ 4.9
AFUDC – Equity			
WE	**$ 3.7**	$ 3.9	$ 3.1
WPS	**5.7**	4.6	4.1
WG	**1.3**	0.6	0.9
UMERC	**3.3**	5.4	0.2
WBS	**0.2**	0.6	3.0
Other	**0.2**	0.1	0.1
Total AFUDC – Equity	**$ 14.4**	$ 15.2	$ 11.4

(i) 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 ERP 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.

As of January 1, 2020, we started capitalizing implementation costs related to cloud computing arrangements that are hosted service contracts. We will 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. The presentation of these costs, along with the related amortization, will follow the prepaid hosting fees.

(j) 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. Our reporting units containing goodwill perform annual goodwill impairment tests during the third quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit 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 9, Goodwill, for more information. Intangible assets with definite lives are reviewed for impairment on a quarterly basis.

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. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain 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. See Note 6, Property, Plant, and Equipment, for more information.

The carrying amounts of 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.

(k) 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 8, Asset Retirement Obligations, for more information.

(l) Stock-Based Compensation—In accordance with the shareholder approved 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. The number of shares of common stock authorized for issuance under the plan is 34.3 million.

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.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, which modified certain aspects of the accounting for stock-based compensation awards. This ASU became effective for us on January 1, 2017. Under the new guidance, all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement on a prospective basis. Prior to January 1, 2017, these amounts were recorded in additional paid in capital on the balance sheet, and excess tax benefits could only be recognized to the extent they reduced taxes payable. In the first quarter of 2017, we recorded a $15.7 million cumulative-effect adjustment to increase retained earnings for excess tax benefits that had not been recognized in prior years as they did not reduce taxes payable. As allowed under this ASU, we have elected to 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 the event of 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:

	2019	2018	2017
Stock options granted	**476,418**	710,710	552,215
Estimated weighted-average fair value per stock option	**$ 8.60**	$ 7.71	$ 7.45
Assumptions used to value the options:			
Risk-free interest rate	**2.5% – 2.7%**	1.6% – 2.8%	0.7% – 2.5%
Dividend yield	**3.6%**	3.5%	3.5%
Expected volatility	**17.0%**	18.0%	19.0%
Expected life (years)	**8.5**	5.9	6.8

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. This same vesting schedule is followed for restricted shares that were granted to non-employee directors prior to 2017. Restricted shares granted to certain officers and all non-employee directors after January 1, 2017, 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 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 10, Common Equity, for more information on our stock-based compensation plans.

(m) 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. There were no securities that had an anti-dilutive effect for the years ended December 31, 2019, 2018, and 2017.

(n) Leases—In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which revised the previous guidance (Topic 840) regarding accounting for leases. Revisions include requiring a lessee to recognize a lease asset and a lease liability on its balance sheet for each lease, including operating leases with an initial term greater than 12 months. In addition, required quantitative and qualitative disclosures related to lease agreements were expanded.

As required, we adopted Topic 842 effective January 1, 2019. We utilized the following practical expedients, which were available under ASU 2016-02, in our adoption of the new lease guidance.

- We did not reassess whether any expired or existing contracts were leases or contained leases.
- We did not reassess the lease classification for any expired or existing leases (that is, all leases that were classified as operating leases in accordance with Topic 840 continue to be classified as operating leases, and all leases that were classified as capital leases in accordance with Topic 840 are classified as finance leases).
- We did not reassess the accounting for initial direct costs for any existing leases.

We did not elect the practical expedient allowing entities to account for the nonlease components in lease contracts as part of the single lease component to which they were related. Instead, in accordance with ASC 842-10-15-31, our policy is to account for each lease component separately from the nonlease components of the contract.

We did not elect the practical expedient to use hindsight in determining the lease term and in assessing impairment of our right of use assets. No impairment losses were included in the measurement of our right of use assets upon our adoption of Topic 842.

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate under Topic 842 land easements that were already in existence or had expired at the time of the entity's adoption of Topic 842. Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. We elected this practical expedient, resulting in none of our land easements being treated as leases upon our adoption of Topic 842.

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented. We did not require a cumulative-effect adjustment upon adoption of Topic 842.

Right of use assets and related lease liabilities related to our operating leases that were recorded upon adoption of Topic 842 were $49.0 million and $48.8 million, respectively. Regarding our power purchase agreement that meets the criteria of a finance lease, while the adoption of Topic 842 changed the classification of expense related to this lease on a prospective basis, it had no impact on the total amount of lease expense recorded, and did not impact the lease asset and related liability amounts recorded on our balance sheets.

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.

As of February 27, 2020, we have not entered into any material leases that have not yet commenced.

See Note 14, Leases, for more information.

(o) 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.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. Production tax credits 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 15, Income Taxes, for more information.

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

In February 2018, the FASB issued ASU 2018-02, Income Statement – Reporting Comprehensive Income. The amendments in this update allowed entities to reclassify the income tax effects that are stranded in accumulated other comprehensive income as a result of the Tax Legislation to retained earnings. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We early adopted the amendments in the fourth quarter of 2018 and reclassified the stranded tax effects associated with the Tax Legislation from accumulated other comprehensive income to retained earnings. As of December 31, 2018, our accumulated other comprehensive income decreased $0.6 million as a result of adopting ASU 2018-02. The adoption of this guidance had no impact on our results of operations or cash flows.

(p) 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 16, Fair Value Measurements, for more information.

(q) 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 17, Derivative Instruments, for more information.

(r) 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 18, Guarantees, for more information.

(s) Employee Benefits—The costs of pension and OPEB 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 19, Employee Benefits, for more information.

(t) 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.

(u) 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 product landfill sites and manufactured gas plant sites. See Note 8, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 23, 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 Commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and coal combustion product landfill sites. 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.

(v) Customer Concentrations of Credit Risk—We provide regulated electric service to customers in Wisconsin and Michigan and regulated natural gas service to customers in Wisconsin, Illinois, Minnesota, and Michigan. 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, 2019. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2019.

NOTE 2—ACQUISITIONS

On January 1, 2018, we adopted ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update clarify the definition of a business and provide guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 also clarifies that transaction costs are capitalized in an asset acquisition but expensed in a business combination.

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 with an unaffiliated third party for all of the energy to be produced by the facility for 12 years. Under the Tax Legislation, WECI's investment in Thunderhead is expected to qualify for production tax credits and 100% bonus depreciation. The transaction is subject to FERC approval and commercial operation is expected to begin at the end of 2020, at which time the transaction is expected to close. 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 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. Under the Tax Legislation, WECI's investment in Upstream qualifies for production tax credits and 100% bonus depreciation. 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.

(in millions)	
Current assets	$ 1.5
Net property, plant, and equipment	341.6
Other long-term assets *	22.9
Current liabilities	(4.6)
Long-term liabilities	(15.0)
Noncontrolling interest	(69.0)
Total purchase price	**$ 277.4**

* Includes $8.1 million of restricted cash.

Acquisition of a Wind Generation Facility in South Dakota

In December 2018, WECI acquired an 80% ownership interest in Coyote Ridge, a 96.7 MW wind generating facility located in Brookings County, South Dakota, for $61.4 million, which included transaction costs. In December 2019, Coyote Ridge achieved commercial operation and WECI made an additional investment of $84.0 million related to capital expenditures for the project for a total investment of $145.4 million. The project has an offtake agreement with an unaffiliated third party for all of the energy produced for 12 years. Under the Tax Legislation, WECI's investment in Coyote Ridge qualifies for production tax credits and 100% bonus depreciation. 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. Coyote Ridge is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired at the date of the acquisition.

(in millions)		
Net property, plant, and equipment	$	66.4
Noncontrolling interest		(5.0)
Total purchase price	$	61.4

Acquisition of Wind Generation Facilities in Illinois

In January 2020, WECI signed an agreement to acquire an 80% ownership interest in Blooming Grove, a 250 MW wind generating facility under construction in McLean County, Illinois, for a total investment of approximately $345 million. In February 2020, WECI agreed to acquire an additional 10% ownership interest in Blooming Grove for $44 million. Blooming Grove has long-term offtake agreements for all the energy produced with affiliates of two investment grade multinational companies. Under the Tax Legislation, WECI's investment in Blooming Grove is expected to qualify for production tax credits and 100% bonus depreciation. The transaction is subject to FERC approval and commercial operation is expected to begin by the end of 2020, at which time the transaction is expected to close. In addition to the customary covenants and closing conditions contained in the agreement, if Blooming Grove does not achieve commercial operation by the end of 2020 and any related potential adverse consequences are not otherwise mitigated, we may terminate the agreement in our sole discretion. Blooming Grove will be included in the non-utility energy infrastructure segment.

In August 2018, WECI completed the acquisition of an 80% ownership interest in Bishop Hill III, a 132.1 MW wind generating facility located in Henry County, Illinois, known as Bishop Hill III, for $144.7 million, which includes transaction costs and is net of restricted cash acquired of $4.5 million. In December 2018, WECI completed the acquisition of an additional 10% ownership interest in Bishop Hill III for $18.2 million. Bishop Hill III has an offtake agreement with an unaffiliated company for the sale of all of the energy produced by the facility for 22 years. Under the Tax Legislation, WECI's investment in Bishop Hill III qualifies for production tax credits and 100% bonus depreciation. Bishop Hill III 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	$	1.4
Net property, plant, and equipment		190.2
Other long-term assets *		4.5
Current liabilities		(1.6)
Long-term liabilities		(8.3)
Noncontrolling interest		(18.8)
Total purchase price	$	167.4

* Represents restricted cash.

Acquisition of a Wind Generation Facility in Wisconsin

In April 2018, WPS, along with two unaffiliated utilities, completed the purchase of Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The aggregate purchase price was $172.9 million of which WPS's proportionate share was 44.6%, or $77.1 million. In addition, WPS incurred $1.9 million of transaction costs that were recorded as a regulatory asset. Since 2008 and up until the acquisition, WPS purchased 44.6% of the facility's energy output under a power purchase agreement.

The table below shows the allocation of the purchase price to the assets acquired at the date of the acquisition, which are included in rate base.

(in millions)		
Current assets	$	0.2
Net property, plant, and equipment		76.9
Total purchase price	$	77.1

Under a joint ownership agreement with the two other utilities, WPS is entitled to its share of generating capability and output of the facility equal to its ownership interest. WPS is also paying its ownership share of additional capital expenditures and operating expenses. Forward Wind Energy Center is included in the Wisconsin segment.

Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, we completed the acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Bluewater is included in the non-utility energy infrastructure segment.

(in millions)		
Current assets	$	2.0
Net property, plant, and equipment		217.6
Goodwill		7.3
Current liabilities		(0.9)
Total purchase price	$	226.0

NOTE 3—DISPOSITIONS

Corporate and Other Segment

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

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 investment tax credits, 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.

Sale of Bostco LLC Real Estate Holdings

In March 2017, we sold the remaining real estate holdings of Bostco located in downtown Milwaukee, Wisconsin, which included retail, office, and residential space, and in October 2018, Bostco was dissolved. During the first quarter of 2017, we recorded an insignificant gain on the sale, which was included in other income, net 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 associated with these assets 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.

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 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 are impacted by regulatory activities within their jurisdictions.

Comparable amounts have not been presented for the year ended December 31, 2017, due to our adoption of ASU 2014-09, Revenues from Contracts with Customers, under the modified retrospective method.

(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)**	**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**

(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, 2018								
Electric	$ 4,432.4	$ —	$ —	$ 4,432.4	$ —	$ —	$ —	$ 4,432.4
Natural gas	1,350.6	1,406.9	428.4	3,185.9	45.4	—	(36.4)	3,194.9
Total regulated revenues	5,783.0	1,406.9	428.4	7,618.3	45.4	—	(36.4)	7,627.3
Other non-utility revenues	—	0.2	16.1	16.3	34.6	7.9	(5.8)	53.0
Total revenues from contracts with customers	5,783.0	1,407.1	444.5	7,634.6	80.0	7.9	(42.2)	7,680.3
Other operating revenues	11.7	(7.1)	(6.3)	(1.7)	388.4	0.8	(388.3)	(0.8)
Total operating revenues	$ 5,794.7	$ 1,400.0	$ 438.2	$ 7,632.9	$ 468.4	$ 8.7	$ (430.5)	$ 7,679.5

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Revenues from Contracts with Customers

Electric Utility Operating Revenues

The following table disaggregates electric utility operating revenues into customer class:

(in millions)	Electric Utility Operating Revenues Year Ended December 31 2019	2018
Residential	**$ 1,608.6**	$ 1,636.3
Small commercial and industrial	**1,384.6**	1,408.6
Large commercial and industrial	**871.9**	912.2
Other	**29.6**	29.9
Total retail revenues	**3,894.7**	3,987.0
Wholesale	**189.5**	210.1
Resale	**163.1**	192.2
Steam	**23.3**	24.1
Other utility revenues	**37.1**	19.0
Total electric utility operating revenues	**$ 4,307.7**	$ 4,432.4

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, 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**
Transport	**72.6**	**245.3**	**31.6**	**349.5**
Other utility revenues *	**(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**

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2018				
Residential	$ 834.5	$ 877.5	$ 263.3	$ 1,975.3
Commercial and industrial	436.7	266.9	140.0	843.6
Total retail revenues	1,271.2	1,144.4	403.3	2,818.9
Transport	70.8	244.1	31.8	346.7
Other utility revenues *	8.6	18.4	(6.7)	20.3
Total natural gas utility operating revenues	$ 1,350.6	$ 1,406.9	$ 428.4	$ 3,185.9

* Includes amounts collected from (refunded to) customers for purchased gas adjustment costs.

Other Non-Utility Operating Revenues

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

	Year Ended December 31	
(in millions)	2019	2018
We Power revenues	**$ 25.4**	$ 25.3
Wind generation revenues	**24.0**	3.6
Appliance service revenues	**16.6**	15.9
Distributed renewable solar project revenues	**4.0**	8.0
Other	**0.2**	0.2
Total other non-utility operating revenues	**$ 70.2**	$ 53.0

Other Operating Revenues

Other operating revenues consist primarily of the following:

	Year Ended December 31	
(in millions)	2019	2018
Late payment charges	**$ 43.7**	$ 40.3
Alternative revenues *	**(9.6)**	(45.6)
Other	**39.7**	4.5
Total other operating revenues	**$ 73.8**	$ (0.8)

* 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 and wholesale true-ups, as discussed in Note 1(d), Operating Revenues.

NOTE 5—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2019	2018	See Note
Regulatory assets (1) (2)			
Pension and OPEB costs (3)	**$ 1,066.6**	$ 1,193.5	19
Plant retirements (4)	**856.4**	832.3	6
Environmental remediation costs (5)	**685.5**	687.1	23
Income tax related items (6)	**457.8**	369.1	15
SSR (7)	**151.5**	316.7	25
AROs	**137.5**	185.4	8
Uncollectible expense (8)	**52.2**	38.7	1(d)
Derivatives	**33.8**	17.8	1(q)
We Power generation (9)	**25.8**	43.0	
Electric transmission costs	**0.3**	58.1	25
Other, net	**60.2**	114.1	
Total regulatory assets	**$ 3,527.6**	$ 3,855.8	
Balance sheet presentation			
Other current assets	**$ 20.9**	$ 50.7	
Regulatory assets	**3,506.7**	3,805.1	
Total regulatory assets	**$ 3,527.6**	$ 3,855.8	

(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 $24.3 million and $18.2 million at December 31, 2019 and 2018, respectively.

(2) As of December 31, 2019, we had $175.1 million of regulatory assets not earning a return, $29.1 million of regulatory assets earning a return based on short-term interest rates, and $151.5 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, the recovery of which depends on the timing of the actual expenditures, as well as uncollectible expense, our electric real-time market pricing program, 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) In accordance with the rate orders issued by the PSCW in December 2019, amounts previously collected from customers for the future removal of our recently retired plants were used to reduce our unrecovered plant balances during December 2019. Any additional removal costs that we incur will increase our plant retirement regulatory assets.

(5) As of December 31, 2019, we had made cash expenditures of $96.3 million related to these environmental remediation costs. The remaining $589.2 million represents our estimated future cash expenditures.

(6) For information on the flow through of tax repairs and the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 25, Regulatory Environment.

(7) As a result of the rate order WE received from the PSCW in December 2019, the regulatory liability related to its mines deferral was offset against its SSR regulatory asset during December 2019. The rate order also authorized recovery of WE's SSR regulatory asset over a 15-year period that began on January 1, 2020.

(8) Represents amounts recoverable from customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(9) Represents amounts recoverable from customers related to WE's costs of the generating units leased from We Power, including subsequent capital additions.

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

(in millions)	2019	2018	See Note
Regulatory liabilities			
Income tax related items (1)	**$ 2,248.8**	$ 2,406.6	15
Removal costs (2)	**1,181.5**	1,329.6	
Pension and OPEB benefits (3)	**354.9**	238.3	19
Energy costs refundable through rate adjustments (4)	**89.8**	39.6	1(d)
Earnings sharing mechanisms (5)	**43.5**	30.0	25
Electric transmission costs (5)	**42.2**	9.7	25
Uncollectible expense (6)	**39.1**	30.5	1(d)
Decoupling	**36.8**	30.5	1(d)
Energy efficiency programs (7)	**30.7**	31.7	
Derivatives	**6.7**	16.4	1(q)
Mines deferral (8)	**—**	120.8	
Other, net	**6.4**	4.7	
Total regulatory liabilities	**$ 4,080.4**	$ 4,288.4	
Balance sheet presentation			
Other current liabilities	**$ 87.6**	$ 36.8	
Regulatory liabilities	**3,992.8**	4,251.6	
Total regulatory liabilities	**$ 4,080.4**	$ 4,288.4	

(1) For information on the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 25, Regulatory Environment.

(2) 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 8, Asset Retirement Obligations, for more information on our legal obligations.

(3) 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.

(4) Represents an over-collection of energy costs that will be refunded to customers in the future. When the rates we charge to customers include energy costs that are higher than our actual energy costs, any over-collection outside of the allowable energy cost price variance is refunded to customers.

(5) Based on orders received from the PSCW, WE was required to apply the refunds due to customers from its earnings sharing mechanism to its electric transmission escrow through 2019. As a result, $38.6 million of WE's earnings sharing refunds were reflected in its electric transmission regulatory liability at December 31, 2019, and $37.2 million of WE's earnings sharing refunds were netted against its electric transmission regulatory asset at December 31, 2018.

(6) Represents amounts refundable to customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(7) Represents amounts refundable to customers related to programs at the utilities designed to meet energy efficiency standards.

(8) Represents the deferral of revenues less the associated cost of sales related to Tilden, which were not included in the PSCW's 2015 rate order. As a result of the rate order WE received from the PSCW in December 2019, this regulatory liability was offset against WE's SSR regulatory asset during December 2019.

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2019	2018
Electric – generation	$ 6,858.8	$ 6,410.6
Electric – distribution	7,018.1	6,534.6
Natural gas – distribution, storage, and transmission	11,602.7	10,766.3
Property, plant, and equipment to be retired, net	—	174.8
Other	1,696.7	1,649.1
Less: Accumulated depreciation	8,073.7	7,573.6
Net	19,102.6	17,961.8
CWIP	820.4	707.5
Net utility property, plant, and equipment	19,923.0	18,669.3
We Power generation	3,245.7	3,244.4
Renewable generation	716.5	193.3
Natural gas storage	245.9	244.8
Net non-utility energy infrastructure	4,208.1	3,682.5
Corporate services	180.4	171.0
Other	88.8	127.1
Less: Accumulated depreciation	805.0	731.5
Net	3,672.3	3,249.1
CWIP	24.8	82.5
Net non-utility and other property, plant, and equipment	3,697.1	3,331.6
Total property, plant, and equipment	$ 23,620.1	$ 22,000.9

Pleasant Prairie Power Plant

The Pleasant Prairie power plant was retired on April 10, 2018. The net book value of this plant was $615.1 million at December 31, 2019, 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 $20.6 million. The net amount of $594.5 million was classified as a regulatory asset on our balance sheets as a result of the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $172.1 million related to the retired Pleasant Prairie power plant. Effective with 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 and on all but $100 million of the net book value of the Pleasant Prairie power plant. In accordance with its PSCW rate order received in December 2019, WE will seek a financing order from the PSCW to securitize the remaining $100 million. See Note 25, 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 $162.7 million at December 31, 2019, 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 $6.4 million. The net amount of $156.3 million was classified as a regulatory asset on our balance sheets as a result of the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $46.5 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. However, this approval is subject to refund pending the outcome of settlement proceedings. See Note 25, Regulatory Environment, for more information.

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 $36.3 million at December 31, 2019, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheets 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 $5.3 million at December 31, 2019, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheets 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.

Severance Liability for Plant Retirements

In December 2017, a severance liability of $29.4 million was recorded in other current liabilities on our balance sheets related to these plant retirements. Activity related to this severance liability for the years ended December 31 was as follows:

(in millions)	**2019**	2018
Severance liability at January 1	$ 15.7	$ 29.4
Severance payments	**(7.2)**	(10.7)
Other	**(6.4)**	(3.0)
Total severance liability at December 31	**$ 2.1**	$ 15.7

NOTE 7—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 in operating expenses in the income statements.

Information related to jointly owned utility facilities at December 31, 2019 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 (2)**	**Forward Wind Energy Center**
Ownership	**83.34%**	**70.0%**	**27.6%**	**44.6%**
Share of rated capacity (MW) (1)	**1,054.3**	**386.0**	**313.9**	**8.4**
In-service date	**2010 and 2011**	**2008**	**1975 and 1978**	**2008**
Property, plant, and equipment	**$ 2,447.9**	**$ 663.2**	**$ 422.3**	**$ 118.7**
Accumulated depreciation	**$ (416.1)**	**$ (232.4)**	**$ (129.5)**	**$ (46.4)**
CWIP	**$ 0.8**	**$ 5.3**	**$ 1.8**	**$ 0.1**

(1) Capacity for our electric generation 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 2020 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.

(2) Columbia Energy Center is jointly owned by Wisconsin Power and Light, Madison Gas and Electric, and WPS. In October 2016, Wisconsin Power and Light received an order from the PSCW approving amendments to the Columbia Energy Center joint operating agreement between the parties allowing WPS and Madison Gas and Electric to forgo certain capital expenditures at the Columbia Energy Center. As a result, Wisconsin Power and Light will incur these capital expenditures in exchange for a proportional increase in its ownership share of the Columbia Energy Center. Based upon the additional capital expenditures Wisconsin Power and Light expects to incur through June 1, 2020, WPS's ownership interest would decrease to 27.5%.

WPS has partnered with an unaffiliated utility to construct two solar projects in Wisconsin. Badger Hollow I is located in Iowa County, Wisconsin, and Two Creeks is located in Manitowoc County, Wisconsin. Once constructed, WPS will own 100 MW of the output of each project for a total of 200 MW. The PSCW approved the acquisition of these two projects in April 2019. Construction began at Two Creeks and Badger Hollow I in August 2019 and October 2019, respectively. Commercial operation of both projects is targeted for the end of 2020. The CWIP balances for Badger Hollow I and Two Creeks as of December 31, 2019 were $32.5 million and $87.3 million, respectively.

In August 2019, WE, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire an ownership interest in a proposed solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin. At its meeting on February 20, 2020, the PSCW approved the acquisition of this project. The approval is still subject to WE's receipt and review of a final written order from the PSCW. Once constructed, WE will own 100 MW of the output of this project. Commercial operation of Badger Hollow II is targeted for the end of 2021.

NOTE 8—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 disposal of PCB-contaminated transformers; the closure of fly-ash 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.

AROs have also been recorded at Bishop Hill III, Coyote Ridge, and Upstream for the dismantling of 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)	2019	2018	2017
Balance as of January 1	**$ 461.4**	$ 573.7	$ 557.7
Accretion	**22.1**	28.0	27.5
Additions and revisions to estimated cash flows	**39.1** (1)	(104.5) (2)	26.5
Liabilities settled	**(39.1)**	(35.8)	(38.0)
Balance as of December 31	**$ 483.5**	$ 461.4	$ 573.7

(1) 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, the wind generation projects known as Upstream and Coyote Ridge. See Note 2, Acquisitions, for more information on Upstream and Coyote Ridge. AROs decreased $7.3 million due to revisions made to estimated cash flows for the abatement of asbestos at WE.

(2) AROs decreased $127.3 million in 2018 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL. Also in 2018, AROs increased $10.7 million as a result of revisions made to estimated cash flows for the abatement of asbestos at WPS's Pulliam power plant, and a $10.9 million ARO was recorded for the legal requirement to dismantle, at retirement, the wind generation projects known as Forward Wind Energy Center and Bishop Hill III. See Note 2, Acquisitions, for more information on Forward Wind Energy Center and Bishop Hill III.

NOTE 9—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 changes to our goodwill balances by segment during the years ended December 31, 2019 and 2018:

	Wisconsin		Illinois		Other States		Non-Utility Energy Infrastructure		Total	
(in millions)	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
Goodwill balance as of January 1	**$ 2,104.3**	$ 2,104.3	**$ 758.7**	$ 758.7	**$ 183.2**	$ 183.2	**$ 6.6**	$ 7.3	**$ 3,052.8**	$ 3,053.5
Adjustment to Bluewater purchase price allocation (1)	**—**	—	**—**	—	**—**	—	**—**	(0.7)	**—**	(0.7)
Goodwill balance as of December 31 (2)	**$ 2,104.3**	$ 2,104.3	**$ 758.7**	$ 758.7	**$ 183.2**	$ 183.2	**$ 6.6**	$ 6.6	**$ 3,052.8**	$ 3,052.8

(1) See Note 2, Acquisitions, for more information on the acquisition of Bluewater.

(2) We had no accumulated impairment losses related to our goodwill as of December 31, 2019.

As of July 1, 2019, annual impairment tests were completed at all of our reporting units that carried a goodwill balance. No impairments resulted from these tests.

NOTE 10—COMMON EQUITY

Stock-Based Compensation Plans

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)	2019	2018	2017
Stock options	**$ 4.4**	$ 5.2	$ 3.4
Restricted stock	**7.1**	10.7	5.4
Performance units	**38.7**	20.2	20.2
Stock-based compensation expense	**$ 50.2**	$ 36.1	$ 29.0
Related tax benefit	**$ 13.8**	$ 9.9	$ 11.6

Stock-based compensation costs capitalized during 2019, 2018, and 2017 were not significant.

Stock Options

The following is a summary of our stock option activity during 2019:

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, 2019	4,452,533	$ 48.86		
Granted	**476,418**	**$ 68.18**		
Exercised	**(1,609,948)**	**$ 41.63**		
Forfeited	**(69,085)**	**$ 62.33**		
Outstanding as of December 31, 2019	**3,249,918**	**$ 54.98**	**6.3**	**$ 121.0**
Exercisable as of December 31, 2019	**1,744,386**	**$ 46.92**	**4.8**	**$ 79.0**

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, 2019. This is calculated as the difference between our closing stock price on December 31, 2019, 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, 2019, 2018, and 2017 was $62.4 million, $32.4 million, and $33.8 million, respectively. The actual tax benefit from option exercises for the same periods was approximately $17.1 million, $8.9 million, and $13.5 million, respectively.

As of December 31, 2019, approximately $2.1 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 2020, the Compensation Committee awarded 512,139 non-qualified stock options with a weighted-average exercise price of $91.49 and a weighted-average grant date fair value of $10.82 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 2019:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2019	234,627	$ 61.01
Granted	**97,343**	**$ 68.18**
Released	**(192,291)**	**$ 60.76**
Forfeited	**(5,570)**	**$ 62.99**
Outstanding and unvested as of December 31, 2019	**134,109**	**$ 66.48**

The intrinsic value of restricted stock released was $13.4 million, $7.9 million, and $5.4 million for the years ended December 31, 2019, 2018, and 2017, respectively. The actual tax benefit from released restricted shares for the same years was $3.7 million, $2.2 million, and $2.1 million, respectively.

As of December 31, 2019, approximately $2.4 million of unrecognized compensation cost related to unvested and outstanding restricted stock was expected to be recognized over the next 1.6 years on a weighted-average basis.

During the first quarter of 2020, the Compensation Committee awarded 84,540 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 $91.49 per share.

Performance Units

During 2019, 2018, and 2017, the Compensation Committee awarded 148,036; 217,560; and 237,650 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $18.7 million, $9.7 million, and $6.7 million were settled during 2019, 2018, and 2017, respectively. The actual tax benefit from the distribution of performance units for the same years was $4.4 million, $2.2 million, and $2.1 million, respectively.

At December 31, 2019, we had 539,475 performance units outstanding, including dividend equivalents. A liability of $58.1 million was recorded on our balance sheet at December 31, 2019 related to these outstanding units. As of December 31, 2019, approximately $20.5 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.6 years on a weighted-average basis.

During the first quarter of 2020, we settled performance units with an intrinsic value of $34.2 million. The actual tax benefit from the distribution of these awards was $8.4 million. In January 2020, the Compensation Committee also awarded 140,455 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, 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 twelve 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.

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 12, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2019, restricted net assets of our consolidated subsidiaries totaled approximately $7.4 billion. Our equity in undistributed earnings of investees accounted for by the equity method was approximately $363 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 2019, 2018, or 2017.

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)	2019	2018	2017
Shares purchased	**1.8**	1.1	1.1
Cost of shares purchased	**$ 140.1**	$ 72.4	$ 71.3

Common Stock Dividends

During the year ended December 31, 2019, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 17, 2019	March 1, 2019	$0.59	First quarter
April 18, 2019	June 1, 2019	$0.59	Second quarter
July 18, 2019	September 1, 2019	$0.59	Third quarter
October 17, 2019	December 1, 2019	$0.59	Fourth quarter

On January 16, 2020, our Board of Directors declared a quarterly cash dividend of $0.6325 per share, which equates to an annual dividend of $2.53 per share. The dividend is payable on March 1, 2020, to shareholders of record on February 14, 2020. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

NOTE 11—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2019 and 2018:

(in millions, except share and per share amounts)	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WEC Energy Group				
$.01 par value Preferred Stock	**15,000,000**	**—**	**—**	**$ —**
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 12—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)	**2019**	**2018**
Commercial paper		
Amount outstanding at December 31	**$ 830.8**	$ 1,440.1
Average interest rate on amounts outstanding at December 31	**2.00%**	2.92%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2019, was $1,039.2 million with a weighted-average interest rate during the period of 2.58%.

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, 2019, 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 program, including remaining available capacity under these facilities as of December 31:

(in millions)	**Maturity**	**2019**
WEC Energy Group	October 2022	**$ 1,200.0**
WE	October 2022	**500.0**
WPS	October 2022	**400.0**
WG	October 2022	**350.0**
PGL	October 2022	**350.0**
Total short-term credit capacity		**$ 2,800.0**
Less:		
Letters of credit issued inside credit facilities		**$ 2.3**
Commercial paper outstanding		**830.8**
Available capacity under existing agreements		**$ 1,966.9**

Each of these 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 our credit agreement, we must ensure that certain of our subsidiaries comply with several of the covenants contained therein.

NOTE 13—LONG-TERM DEBT

The following table is a summary of our long-term debt outstanding (excluding finance/capital leases) as of December 31:

(in millions)		2019		2018	
Long-term debt	**Maturity Date**	**Weighted Average Interest Rate**	**Balance**	**Weighted Average Interest Rate**	**Balance**
WEC Energy Group Senior Notes (unsecured) (1)	2020-2033	**3.47%**	**$ 2,050.0**	3.54%	$ 1,700.0
WEC Energy Group Junior Notes (unsecured) (1) (2)	2067	**4.50%**	**500.0**	4.85%	500.0
WE Debentures (unsecured)	2021-2095	**4.26%**	**2,785.0**	4.50%	2,735.0
WPS Senior Notes (unsecured)	2021-2049	**4.04%**	**1,625.0**	4.21%	1,325.0
WG Debentures (unsecured)	2024-2046	**3.65%**	**640.0**	4.04%	490.0
Integrys Senior Notes (unsecured)	2020	**4.17%**	**250.0**	4.17%	250.0
Integrys Junior Notes (unsecured) (3)	2073	**6.00%**	**400.0**	6.00%	400.0
PGL First and Refunding Mortgage Bonds (secured) (4)	2024-2047	**3.59%**	**1,520.0**	3.88%	1,195.0
NSG First Mortgage Bonds (secured) (5)	2027-2043	**3.81%**	**132.0**	3.81%	132.0
MERC Senior Notes (unsecured)	2027-2047	**3.51%**	**120.0**	3.51%	120.0
MGU Senior Notes (unsecured)	2027-2047	**3.51%**	**90.0**	3.51%	90.0
UMERC Senior Notes (unsecured)	2029	**3.26%**	**160.0**	N/A	—
Bluewater Gas Storage Senior Notes (unsecured) (6)	2020-2047	**3.76%**	**120.3**	3.76%	122.7
ATC Holding Senior Notes (unsecured)	2025-2030	**4.05%**	**475.0**	4.34%	240.0
We Power Subsidiaries Notes (secured, nonrecourse) (6) (7)	2020-2041	**5.57%**	**1,005.2**	5.56%	1,037.9
WECC Notes (unsecured)	2028	**6.94%**	**50.0**	6.94%	50.0
Total			**11,922.5**		10,387.6
Integrys acquisition fair value adjustment			**14.3**		20.6
Unamortized debt issuance costs			**(52.9)**		(44.7)
Unamortized discount, net and other			**(25.6)**		(27.8)
Total long-term debt, including current portion (8)			**11,858.3**		10,335.7
Current portion of long-term debt			**(686.9)**		(360.1)
Total long-term debt			**$ 11,171.4**		$ 9,975.6

(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 4.02% and 4.73% as of December 31, 2019 and 2018, 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. The effective rates of 4.50% and 4.85% as of December 31, 2019 and 2018, respectively, were blended rates of the variable and fixed portions.

(3) Effective August 2023, Integrys's $400.0 million of 2013 6.00% Junior Subordinated Notes due 2073 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 equal principal amounts of certain collateralized First Mortgage Bonds.

The mandatory reset date for PGL's $50.0 million of 1.875% Bonds, series WW, is August 1, 2020.

(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 and We Power's subsidiaries amortizes on a mortgage-style basis.

(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) The amount of long-term debt on our balance sheets includes finance/capital lease obligations of $45.9 million and $23.3 million at December 31, 2019 and 2018, 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 2019, we issued $350.0 million of 3.10% Senior Notes due March 8, 2022. We used the net proceeds to repay short-term debt, and for working capital and other general corporate purposes.

Wisconsin Electric Power Company

In December 2019, WE issued $300.0 million of 2.05% Debentures due December 15, 2024, and used the net proceeds to repay WE's $250.0 million of 4.25% Debentures which matured in December 2019, to repay short-term debt, and for working capital and other corporate purposes.

Wisconsin Public Service Corporation

In August 2019, WPS issued $300.0 million of 3.30% Senior Notes due September 1, 2049, and used the net proceeds to repay short-term debt and for working capital and other corporate purposes.

Wisconsin Gas LLC

In October 2019, WG issued $150.0 million of 2.38% Debentures due November 1, 2024, and used the net proceeds to repay short-term debt and for working capital and other corporate purposes.

The Peoples Gas Light and Coke Company

In September 2019, PGL issued $275.0 million of 2.96% Bonds, Series GGG due September 1, 2029. PGL used the net proceeds to repay PGL's $75.0 million of 4.63% Bonds, Series UU which matured in September 2019, and for general corporate purposes, including capital expenditures and the repayment of short-term debt.

In November 2019, PGL issued $75.0 million of 2.64% Bonds, Series HHH due November 1, 2024 and $50.0 million of 3.06% Bonds, Series III due November 1, 2031. PGL used the net proceeds for general corporate purposes, including capital expenditures and the repayment of short-term debt.

Upper Michigan Energy Resources Corporation

In August 2019, UMERC issued $160.0 million of 3.26% Senior Notes due August 28, 2029, and used the net proceeds to redeem its long-term debt to WEC Energy Group and for working capital and general corporate purposes.

ATC Holding LLC

In September 2019, ATC Holding issued $235.0 million of 3.75% Senior Notes due September 16, 2029, and used the net proceeds to balance its capital structure.

The following table shows the long-term debt securities (excluding finance leases) maturing within one year of December 31, 2019:

(in millions)	Interest Rate	Maturity Date *	Principal Amount
WEC Energy Group Senior Notes (unsecured)	2.45%	June	$ 400.0
Integrys Senior Notes (unsecured)	4.17%	November	250.0
Bluewater Gas Storage Senior Notes (unsecured)	3.76%	Semi-annually	2.5
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	4.91%	Monthly	6.6
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	5.209%	Semi-annually	12.6
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	4.673%	Semi-annually	9.7
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	6.00%	Monthly	5.5
Total			$ 686.9

* Maturity dates listed as semi-annually and monthly are associated with debt that amortizes on a mortgage-style basis.

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under finance leases) as of December 31, 2019:

(in millions)	Payments
2020	$ 686.9
2021	1,338.8
2022	390.8
2023	42.8
2024	570.0
Thereafter	8,893.2
Total	$ 11,922.5

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 14—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.
- Rail cars we are leasing to transport coal to various generating facilities through February 2021.

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 Lease

Power Purchase Commitment

In 1997, we entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MWs of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. When the contract expires in 2022, we may, at our option and with proper notice, renew for another ten years, purchase the generating facility at fair market value, or allow the contract to expire. At lease inception we recorded this leased facility and corresponding obligation on our balance sheets at the estimated fair value of the plant's electric generating facilities. Minimum lease payments are a function of the 236 MWs of firm capacity we receive from the plant and the fixed monthly capacity rate published in the lease.

Prior to our adoption of Topic 842 on January 1, 2019, we accounted for this finance lease under Topic 980-840, Regulated Operations – Leases, as follows:

- We recorded our minimum lease payments as purchased power expense in cost of sales on our income statement.
- We recorded the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under finance lease accounting rules as a deferred regulatory asset on our balance sheets.

In conjunction with our adoption of Topic 842, while the timing of expense recognition related to this finance lease did not change, classification of the lease expense changed as follows:

- Effective January 1, 2019, the minimum lease payments under the power purchase contract were no longer classified within cost of sales in our income statements, but were instead recorded as a component of depreciation and amortization and interest expense in accordance with Topic 980-842, Regulated Operations – Leases.
- In accordance with Topic 980-842, the timing of lease expense did not change for this finance lease upon adoption of Topic 842, and still resembled the expense recognition pattern of an operating lease, as the amortization of the right of use assets was modified from what would typically be recorded for a finance lease under Topic 842.
- We continue to 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 deferred regulatory asset on our balance sheets.

Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to $78.5 million in 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the finance lease was $18.4 million at December 31, 2019, and will decrease to zero over the remaining life of the contract.

Two Creeks Solar Project

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.

We treat these land lease contracts as operating leases for rate-making purposes. Our total obligation under the finance leases for Two Creeks was $7.7 million as of December 31, 2019, and will decrease to zero over the remaining lives of the leases.

Badger Hollow Solar Farm 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 1,400 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.

We treat these land lease contracts as operating leases for rate-making purposes. Our total obligation under the finance leases for Badger Hollow I was $19.8 million as of December 31, 2019, and will decrease to zero over the remaining lives of the leases.

Amounts Recognized in the Financial Statements

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)	2019	2018	2017
Finance/capital lease expense (1)	**$ 8.2**	$ 7.7	$ 7.2
Operating lease expense (2)	**5.5**	5.6	6.4
Short-term lease expense (2)	**0.6**	1.5	0.8
Total lease expense	**$ 14.3**	$ 14.8	$ 14.4
Other information			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from finance/capital leases (3)	**$ 3.3**	$ 7.7	$ 7.2
Operating cash flows from operating leases	**$ 6.0**	$ 6.5	$ 7.1
Financing cash flows from finance leases (3)	**$ 4.9**		
Non-cash activities:			
Right of use assets obtained in exchange for finance lease liabilities	**$ 27.2**		
Right of use assets obtained in exchange for operating lease liabilities	**$ 49.0**		
Weighted-average remaining lease term – finance leases	**31.5 years**		
Weighted-average remaining lease term – operating leases	**12.9 years**		
Weighted-average discount rate – finance lease (4)	**6.7%**		
Weighted average discount rate – operating leases (4)	**4.4%**		

(1) For the year ended December 31, 2019, finance lease expense included amortization of right of use assets in the amount of $4.9 million (included in depreciation and amortization expense) and interest on lease liabilities of $3.3 million (included in interest expense). For the years ended December 31, 2018 and 2017, total capital lease expense related to the long-term power purchase agreement was included in cost of sales.

(2) Operating and short-term lease expense were included as a component of operation and maintenance for the years ended December 31, 2019, 2018, and 2017.

(3) Prior to our adoption of Topic 842 on January 1, 2019, all cash flows related to the finance lease were recorded as a component of operating cash flows.

(4) Because our operating 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 for our operating leases. For our power purchase agreement that meets the definition of a finance lease, the rate implicit in the lease was readily determinable. For our solar land leases that are finance leases, 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)	2019	2018
Long-term power purchase commitment		
Under finance/capital lease	**$ 140.3**	$ 140.3
Accumulated amortization	**(126.6)**	(120.9)
Total long-term power purchase commitment	**$ 13.7**	$ 19.4
Two Creeks land leases		
Under finance leases	**$ 7.7**	$ —
Accumulated amortization	**(0.1)**	—
Total Two Creeks land leases	**$ 7.6**	**$ —**
Badger Hollow I land leases		
Under finance leases	**$ 19.5**	$ —
Accumulated amortization	**(0.2)**	—
Total Badger Hollow I land leases	**$ 19.3**	**$ —**
Total finance lease right of use assets/capital lease asset	**$ 40.6**	$ 19.4

Right of use assets related to operating leases were $41.4 million at December 31, 2019, and were included in other long-term assets on our balance sheets.

Future minimum lease payments under our operating leases and our finance leases, and the present value of our net minimum lease payments as of December 31, 2019, were as follows:

(in millions)	Total Operating Leases	Power Purchase Commitment	Two Creeks	Badger Hollow I	Total Finance Leases
2020	$ 6.8	$ 8.8	$ 0.2	$ 0.3	$ 9.3
2021	4.8	9.4	0.2	0.7	10.3
2022	4.8	4.2	0.2	0.7	5.1
2023	4.9	—	0.2	0.7	0.9
2024	4.8	—	0.2	0.7	0.9
Thereafter	30.1	—	22.8	53.4	76.2
Total minimum lease payments	56.2	22.4	23.8	56.5	102.7
Less: Interest	(14.8)	(4.0)	(16.1)	(36.7)	(56.8)
Present value of minimum lease payments	41.4	18.4	7.7	19.8	45.9
Less: Short-term lease liabilities	(4.4)	(6.3)	—	—	(6.3)
Long-term lease liabilities	$ 37.0	$ 12.1	$ 7.7	$ 19.8	$ 39.6

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.

At December 31, 2018, short-term and long-term liabilities under our capital lease were $4.9 million and $18.4 million, respectively. Short-term and long-term lease liabilities related to our finance/capital leases were included in current portion of long-term debt and long-term debt on the balance sheets, respectively.

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NOTE 15—INCOME TAXES

Income Tax Expense

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

(in millions)	2019	2018	2017
Current tax expense (benefit)	**$ (37.9)**	$ (127.5)	$ 111.8
Deferred income taxes, net	**167.7**	300.1	274.4
Investment tax credit, net	**(4.8)**	(2.8)	(2.7)
Total income tax expense	**$ 125.0**	$ 169.8	$ 383.5

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:

	2019		2018		2017 (2)	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 264.4**	**21.0 %**	$ 258.1	21.0 %	$ 555.5	35.0 %
State income taxes net of federal tax benefit	**80.4**	**6.4 %**	71.8	5.8 %	100.8	6.4 %
Tax repairs (1)	**(122.8)**	**(9.8)%**	(120.7)	(9.8)%	—	— %
Federal excess deferred tax amortization	**(34.9)**	**(2.8)%**	(16.8)	(1.4)%	—	— %
Wind production tax credits	**(34.1)**	**(2.7)%**	(12.1)	(1.0)%	(16.8)	(1.1)%
Excess tax benefits – stock options	**(15.8)**	**(1.3)%**	(5.9)	(0.5)%	(10.0)	(0.6)%
Investment tax credit restored	**(4.8)**	**(0.4)%**	(2.8)	(0.2)%	(2.7)	(0.2)%
AFUDC – Equity	**(3.0)**	**(0.2)%**	(3.2)	(0.3)%	(4.0)	(0.3)%
Federal tax reform	**—**	**— %**	—	— %	(226.9)	(14.3)%
Other, net	**(4.4)**	**(0.3)%**	1.4	0.2 %	(12.4)	(0.8)%
Total income tax expense	**$ 125.0**	**9.9 %**	$ 169.8	13.8 %	$ 383.5	24.1 %

(1) 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 offsets the negative income statement impact of holding the regulatory assets level, resulting in no change to net income. See Note 25, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate order.

(2) In 2017, the net impact of tax reform in the amount of $206.7 million is represented in both the Federal tax reform and State income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduced the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. In December 2017, we recorded a tax benefit related to the re-measurement of our deferred taxes in the amount of $2,657 million. Accordingly, the tax benefit related to our regulated utilities was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017. The effects of the Tax Legislation primarily at our non-utility energy infrastructure and corporate and other segments resulted in the recording of an income tax benefit of approximately $206.7 million for the year ended December 31, 2017. This tax benefit was primarily due to a re-measurement of deferred tax assets and liabilities.

On December 22, 2017, the SEC staff issued guidance in SAB 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provided for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, certain amounts related to bonus depreciation and future tax benefit utilization recorded in the financial statements as a result of the Tax Legislation were considered "provisional" and subject to revision at December 31, 2017, and through 2018, as discussed in SAB 118.

In 2018, we considered all available guidance from industry and income tax authorities related to these tax items, and revised our Alternative Minimum Tax Credit valuation allowance, and revised our estimates for re-measurement of deferred income taxes related to guidance on bonus depreciation. See Note 25, Regulatory Environment, for more information on the re-measurement of deferred income taxes. At December 31, 2018, we no longer considered any amounts related to bonus depreciation and future tax benefit utilization "provisional," subject to any additional amendments or technical corrections to the Tax Legislation.

In 2019, we considered all available guidance from industry and income tax authorities related to these tax items, and reversed the valuation allowance we had related to Alternative Minimum Tax Credits due to an IRS Announcement issued January 14, 2019. Any further amendments or technical corrections to the Tax Legislation could subject these tax items to revision.

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

(in millions)	2019	2018
Deferred tax assets		
Tax gross up – regulatory items	**$ 519.8**	$ 579.2
Deferred revenues	**106.3**	129.3
Future tax benefits	**101.0**	70.6
Other	**159.8**	194.4
Total deferred tax assets	**886.9**	973.5
Valuation allowance	**(2.3)**	(11.4)
Net deferred tax assets	**$ 884.6**	$ 962.1
Deferred tax liabilities		
Property-related	**$ 3,609.0**	$ 3,436.9
Investment in affiliates	**531.7**	420.6
Deferred costs – Plant retirements	**232.0**	176.0
Employee benefits and compensation	**131.4**	121.2
Other	**149.8**	195.5
Total deferred tax liabilities	**4,653.9**	4,350.2
Deferred tax liability, net	**$ 3,769.3**	$ 3,388.1

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, 2019 and 2018 are summarized in the tables below:

2019 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2019				
Federal tax credit	**$ —**	**$ 75.4**	**$ —**	**2037**
State net operating loss	**287.1**	**17.6**	**(2.3)**	**2023**
Other state benefits	**—**	**8.0**	**—**	**2019**
Balance as of December 31, 2019	**$ 287.1**	**$ 101.0**	**$ (2.3)**	

2018 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2018				
Federal foreign tax credit	$ —	$ 9.7	$ (9.7)	2018
Other federal tax credit	—	39.3	(1.7)	2038
State net operating loss	275.9	17.0	—	2023
Other state benefits	—	4.6	—	2018
Balance as of December 31, 2018	$ 275.9	$ 70.6	$ (11.4)	

Unrecognized Tax Benefits

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

(in millions)	2019	2018
Balance as of January 1	**$ 20.0**	$ 17.3
Additions for tax positions of prior years	**1.9**	2.8
Additions based on tax positions related to the current year	**0.2**	0.1
Reductions for tax positions of prior years	**(4.2)**	(0.2)
Balance as of December 31	**$ 17.9**	$ 20.0

The amount of unrecognized tax benefits as of both December 31, 2019 and 2018, excludes deferred tax assets related to uncertainty in income taxes of $2.0 million. As of December 31, 2019 and 2018, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $15.9 million and $18.0 million, respectively.

For the years ended December 31, 2019, 2018, and 2017, we recognized $0.1 million of interest expense, $0.5 million of interest expense, and $0.6 million of interest income, respectively, related to unrecognized tax benefits in our income statements. For the years ended December 31, 2019, 2018, and 2017, we recognized no penalties related to unrecognized tax benefits in our income statements. For the year ended December 31, 2019, we had $0.8 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. For the year ended December 31, 2018, we had $0.7 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

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 $11.4 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, 2019, with a few exceptions, we were subject to examination by federal and state or local tax authorities for the 2015 through 2019 tax years in our major operating jurisdictions as follows:

Jurisdiction	**Years**
Federal	2015–2019
Illinois	2015–2019
Michigan	2015–2019
Minnesota	2015–2019
Wisconsin	2015–2019

NOTE 16—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, 2019			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ 1.4**	**$ 2.0**	**$ —**	**$ 3.4**
FTRs	**—**	**—**	**3.1**	**3.1**
Coal contracts	**—**	**0.4**	**—**	**0.4**
Total derivative assets	**$ 1.4**	**$ 2.4**	**$ 3.1**	**$ 6.9**
Investments held in rabbi trust	**$ 85.3**	**$ —**	**$ —**	**$ 85.3**
Derivative liabilities				
Natural gas contracts	**$ 21.4**	**$ 1.3**	**$ —**	**$ 22.7**
Coal contracts	**—**	**0.2**	**—**	**0.2**
Interest rate swaps	**—**	**6.0**	**—**	**6.0**
Total derivative liabilities	**$ 21.4**	**$ 7.5**	**$ —**	**$ 28.9**

	December 31, 2018			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 6.3	$ 1.8	$ —	$ 8.1
FTRs	—	—	7.4	7.4
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 6.3	$ 2.2	$ 7.4	$ 15.9
Investments held in rabbi trust	$ 65.0	$ —	$ —	$ 65.0
Derivative liabilities				
Natural gas contracts	$ 4.7	$ 0.8	$ —	$ 5.5
Coal contracts	—	0.1	—	0.1
Interest rate swaps	—	2.3	—	2.3
Total derivative liabilities	$ 4.7	$ 3.2	$ —	$ 7.9

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, 2019 and 2017, the net unrealized gains included in earnings related to the investments held at the end of the period were $18.7 million and $18.8 million, respectively. The net unrealized gains included in earnings for the year ended December 31, 2018 were not significant.

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

(in millions)	2019	2018	2017
Balance at the beginning of the period	**$ 7.4**	$ 4.4	$ 5.1
Purchases	**12.8**	18.4	13.8
Settlements	**(17.1)**	(15.4)	(14.5)
Balance at the end of the period	**$ 3.1**	$ 7.4	$ 4.4

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:

	2019		2018	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock of subsidiary	**$ 30.4**	**$ 29.5**	$ 30.4	$ 28.3
Long-term debt, including current portion *	**11,858.3**	**13,035.9**	10,335.7	10,554.9

* The carrying amount of long-term debt excludes finance and capital lease obligations of $45.9 million and $23.3 million at December 31, 2019 and 2018, respectively.

The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 17—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, along with their classification on our balance sheets. None of our derivatives are designated as hedging instruments, with the exception of our interest rate swaps, which have been designated as cash flow hedges.

	December 31, 2019		December 31, 2018	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 3.4**	**$ 21.8**	$ 7.7	$ 5.3
FTRs	**3.1**	**—**	7.4	—
Coal contracts	**0.2**	**0.2**	0.2	0.1
Interest rate swaps	**—**	**2.8**	—	0.4
Total other current	**6.7**	**24.8**	15.3	5.8
Other long-term				
Natural gas contracts	**—**	**0.9**	0.4	0.2
Coal contracts	**0.2**	**—**	0.2	—
Interest rate swaps	**—**	**3.2**	—	1.9
Total other long-term	**0.2**	**4.1**	0.6	2.1
Total	**$ 6.9**	**$ 28.9**	$ 15.9	$ 7.9

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, 2019		December 31, 2018		December 31, 2017	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains	Volumes	Gains (Losses)
Natural gas contracts	**183.9 Dth**	**$ (27.1)**	173.2 Dth	$ 24.6	123.1 Dth	$ (8.0)
Petroleum products contracts	**— gallons**	**—**	6.0 gallons	1.6	18.0 gallons	(1.3)
FTRs	**31.2 MWh**	**16.3**	30.5 MWh	15.9	36.2 MWh	14.0
Total		**$ (10.8)**		$ 42.1		$ 4.7

At December 31, 2019 and 2018, we had posted cash collateral of $34.4 million and $2.7 million, respectively, in our margin accounts. At December 31, 2018, we had also received cash collateral of $0.2 million in our margin accounts. We had not received any cash collateral at December 31, 2019.

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

	December 31, 2019		December 31, 2018	
(in millions)	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Gross amount recognized on the balance sheet	**$ 6.9**	**$ 28.9**	$ 15.9	$ 7.9
Gross amount not offset on the balance sheet	**(1.4)**	**(21.4)** (1)	(4.0) (2)	(4.9) (3)
Net amount	**$ 5.5**	**$ 7.5**	$ 11.9	$ 3.0

(1) Includes cash collateral posted of $20.0 million.

(2) Includes cash collateral received of $0.2 million.

(3) Includes cash collateral posted of $1.1 million.

Cash Flow Hedges

Effective January 1, 2019, we adopted ASU 2017-12, Targeted Improvements to Accounting for Hedging Activities. The amendments in this update expand the strategies that qualify for hedge accounting, amend the presentation and disclosure requirements related to hedging activities, and provide overall targeted improvements to simplify hedge accounting in certain situations. The adoption of this standard did not have a significant impact on our financial statements.

As of December 31, 2019, 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 provide a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million of outstanding 2007 Junior Notes through November 15, 2021. As these swaps qualified for cash flow hedge accounting treatment, the related gains and losses are being deferred in accumulated other comprehensive loss and are being amortized to interest expense as interest is 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 loss and in earnings, along with our total interest expense on the income statements, for the years ended December 31:

(in millions)	**2019**	**2018**	**2017**
Derivative losses recognized in other comprehensive loss	**$ (4.8)**	$ (2.9)	$ —
Net derivative gains reclassified from accumulated other comprehensive loss to interest expense	**1.1**	1.6	2.2
Total interest expense line item on the income statements	**501.5**	445.1	415.7

We estimate that during the next twelve months, $1.0 million will be reclassified from accumulated other comprehensive loss as an increase to interest expense.

NOTE 18—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at December 31, 2019	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees				
Guarantees supporting transactions of subsidiaries (1)	**$ 31.4**	$ 10.2	$ 0.2	$ 21.0
Standby letters of credit (2)	**103.0**	1.2	0.2	101.6
Surety bonds (3)	**9.9**	9.9	—	—
Other guarantees (4)	**11.7**	0.9	—	10.8
Total guarantees	**$ 156.0**	$ 22.2	$ 0.4	$ 133.4

(1) Consists of $4.0 million, $6.2 million, and $21.2 million to support the business operations of UMERC, Bluewater, and WECI, respectively.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Primarily for 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 $11.7 million related to other indemnifications, for which a liability of $10.8 million related to workers compensation coverage was recorded on our balance sheets.

NOTE 19—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. New 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)	2019	2018	2019	2018
Change in benefit obligation				
Obligation at January 1	**$ 2,927.2**	$ 3,163.7	**$ 608.2**	$ 818.5
Service cost	**47.0**	47.1	**16.3**	23.7
Interest cost	**120.4**	114.3	**25.7**	29.9
Participant contributions	**—**	—	**12.3**	15.5
Plan amendments	**—**	—	**(4.0)**	(3.5)
Actuarial loss (gain)	**269.3**	(171.8)	**(60.7)**	(222.6)
Benefit payments	**(240.2)**	(226.1)	**(42.3)**	(55.4)
Federal subsidy on benefits paid	**N/A**	N/A	**1.3**	1.0
Transfer	**—**	—	**1.8**	1.1
Obligation at December 31	**$ 3,123.7**	$ 2,927.2	**$ 558.6**	$ 608.2
Change in fair value of plan assets				
Fair value at January 1	**$ 2,690.8**	$ 2,966.8	**$ 771.7**	$ 841.5
Actual return on plan assets	**494.1**	(122.2)	**134.3**	(35.2)
Employer contributions	**62.3**	72.3	**3.6**	5.3
Participant contributions	**—**	—	**12.3**	15.5
Benefit payments	**(240.2)**	(226.1)	**(42.3)**	(55.4)
Fair value at December 31	**$ 3,007.0**	$ 2,690.8	**$ 879.6**	$ 771.7
Funded status at December 31	**$ (116.7)**	$ (236.4)	**$ 321.0**	$ 163.5

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)	2019	2018	2019	2018
Other long-term assets	**$ 188.8**	$ 139.1	**$ 341.7**	$ 210.8
Pension and OPEB obligations	**305.5**	375.5	**20.7**	47.3
Total net (liabilities) assets	**$ (116.7)**	$ (236.4)	**$ 321.0**	$ 163.5

The accumulated benefit obligation for all defined benefit pension plans was $2,992.9 million and $2,804.9 million as of December 31, 2019 and 2018, 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)	2019	2018
Projected benefit obligation	**$ 1,810.1**	$ 1,930.8
Accumulated benefit obligation	**1,754.2**	1,882.2
Fair value of plan assets	**1,504.6**	1,572.7

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Benefits		OPEB Benefits	
(in millions)	2019	2018	2019	2018
Pre-tax accumulated other comprehensive loss (1)				
Net actuarial loss (gain)	**$ 10.6**	$ 14.5	**$ (1.6)**	$ (1.6)
Prior service credits	**—**	—	**(0.1)**	(0.1)
Total	**$ 10.6**	$ 14.5	**$ (1.7)**	$ (1.7)
Net regulatory assets (liabilities) (2)				
Net actuarial loss (gain)	**$ 1,067.7**	$ 1,184.1	**$ (266.6)**	$ (133.0)
Prior service costs (credits)	**2.7**	4.9	**(88.6)**	(100.0)

Total	**$ 1,070.4**	$ 1,189.0	**$ (355.2)**	$ (233.0)

(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 following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2020:

(in millions)	Pension Benefits	OPEB Benefits
Net actuarial loss (gain)	$ 97.1	$ (21.5)
Prior service costs (credits)	1.6	(15.0)
Total 2020 – estimated amortization	$ 98.7	$ (36.5)

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)	2019	2018	2017	2019	2018	2017
Service cost	**$ 47.0**	$ 47.1	$ 44.6	**$ 16.3**	$ 23.7	$ 24.1
Interest cost	**120.4**	114.3	121.8	**25.7**	29.9	32.9
Expected return on plan assets	**(193.3)**	(196.5)	(195.7)	**(54.7)**	(59.5)	(55.5)
Plan settlement	**11.5**	1.0	9.0	**—**	—	—
Amortization of prior service cost (credit)	**2.2**	2.7	2.9	**(15.4)**	(15.4)	(12.3)
Amortization of net actuarial loss	**77.3**	94.0	86.1	**(6.6)**	1.0	3.1
Net periodic benefit cost (credit)	**$ 65.1**	$ 62.6	$ 68.7	**$ (34.7)**	$ (20.3)	$ (7.7)

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	
	2019	2018	2019	2018
Discount rate	**3.41%**	4.30%	**3.39%**	4.27%
Rate of compensation increase	**4.00%**	3.66%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.00%**	6.25%
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**	2024
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**5.91%**	6.01%
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		
	2019	2018	2017
Discount rate	**4.21%**	3.71%	4.11%
Expected return on plan assets	**7.12%**	7.12%	7.11%
Rate of compensation increase	**3.66%**	3.66%	3.60%

	OPEB Benefits		
	2019	**2018**	**2017**
Discount rate	**4.27%**	3.63%	4.04%
Expected return on plan assets	**7.25%**	7.25%	7.25%
Assumed medical cost trend rate (Pre 65)	**6.25%**	6.50%	7.00%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2024**	2024	2021
Assumed medical cost trend rate (Post 65)	**6.01%**	6.09%	7.00%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2028**	2028	2021

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 2020, the expected return on assets assumption is 6.87% for the pension plans and 7.00% for the OPEB plans.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for health care plans. For the year ended December 31, 2019, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	**1% Increase**	**1% Decrease**
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 4.7	$ (3.8)
Effect on health care component of the accumulated postretirement benefit obligations	43.5	(36.5)

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 allocation is 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. The two legacy Wisconsin Energy Corporation OPEB trusts' target asset allocations are 50% equity investments and 50% fixed income investments, and 70% equity investments and 30% fixed income investments, respectively. The two largest legacy OPEB trusts for Integrys have the same target asset allocations of 45% equity investments and 55% fixed income. 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(p), 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, 2019							
	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	**$ 335.6**	**$ —**	**$ —**	**$ 335.6**	**$ 103.0**	**$ —**	**$ —**	**$ 103.0**
International equity	**321.6**	**0.7**	**—**	**322.3**	**107.3**	**0.2**	**—**	**107.5**
Fixed income securities: *								
United States bonds	**94.3**	**887.4**	**—**	**981.7**	**119.1**	**165.9**	**—**	**285.0**
International bonds	**51.5**	**87.0**	**—**	**138.5**	**24.6**	**8.5**	**—**	**33.1**
	$ 803.0	**$ 975.1**	**$ —**	**$ 1,778.1**	**$ 354.0**	**$ 174.6**	**$ —**	**$ 528.6**
Investments measured at net asset value				**$ 1,228.9**				**$ 351.0**
Total	**$ 803.0**	**$ 975.1**	**$ —**	**$ 3,007.0**	**$ 354.0**	**$ 174.6**	**$ —**	**$ 879.6**

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

	December 31, 2018							
	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	$ 281.7	$ —	$ —	$ 281.7	$ 88.2	$ —	$ —	$ 88.2
International equity	279.7	0.7	—	280.4	92.2	0.2	—	92.4
Fixed income securities: *								
United States bonds	123.7	838.8	—	962.5	119.6	150.8	—	270.4
International bonds	16.1	85.5	—	101.6	7.1	8.9	—	16.0
	$ 701.2	$ 925.0	$ —	$ 1,626.2	$ 307.1	$ 159.9	$ —	$ 467.0
Investments measured at net asset value				$ 1,064.6				$ 304.7
Total	$ 701.2	$ 925.0	$ —	$ 2,690.8	$ 307.1	$ 159.9	$ —	$ 771.7

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

The following table sets forth a reconciliation of changes in the fair value of pension and OPEB plan assets categorized as Level 3 in the fair value hierarchy:

	Private Equity and Real Estate		International Equity	
(in millions)	**Pension**	**OPEB**	**Pension**	**OPEB**
Beginning balance at January 1, 2018	$ 100.1	$ 7.7	$ 0.8	$ 0.2
Realized and unrealized gains (losses)	8.0	1.1	(0.1)	—
Purchases	18.3	1.5	—	—
Liquidations	(1.7)	(0.2)	—	—
Transfers out of level 3	(124.7)	(10.1)	(0.7)	(0.2)
Ending balance at December 31, 2018	$ —	$ —	$ —	$ —

Cash Flows

We expect to contribute $11.6 million to the pension plans and $0.9 million to the OPEB plans in 2020, dependent upon various factors affecting us, including our liquidity position and the effects of the Tax Legislation.

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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
2020	$ 236.9	$ 37.1
2021	236.7	34.7
2022	228.4	35.6
2023	226.8	36.1
2024	218.8	36.1
2025-2029	1,004.2	179.5

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 $50.9 million, $49.3 million, and $47.9 million in 2019, 2018, and 2017, respectively.

NOTE 20—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. The corporate managers for ATC and ATC Holdco each have a ten-member board of directors. We have one representative on each board. Each member of the board has only one vote. Due to voting requirements, each individual board member has 10% of the voting control. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	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, the FERC issued an order that addressed the complaints related to ATC's allowed ROE. Due to the numerous rehearing requests filed related to this order, our financials continue to include a $41.9 million liability for potential future refunds that ATC may be required to provide, resulting in reduced equity earnings from ATC. This liability reflects a 10.38% ROE for all periods covered by the complaints.

	2018		
(in millions)	ATC	ATC Holdco	Total
Balance at January 1	$ 1,515.8	$ 37.6	$ 1,553.4
Add: Earnings (loss) from equity method investment	139.6	(2.9)	136.7
Add: Capital contributions	48.2	5.3	53.5
Less: Distributions	78.2	—	78.2
Less: Other	0.1	—	0.1
Balance at December 31	$ 1,625.3	$ 40.0	$ 1,665.3

(in millions)	2017 ATC		2017 ATC Holdco	2017 Total
Balance at January 1	$ 1,443.9	(1)	$ —	$ 1,443.9
Add: Earnings (loss) from equity method investment	166.0		(11.7)	154.3
Add: Capital contributions	60.3		49.3	109.6
Less: Distributions	154.2	(2)	—	154.2
Less: Other	0.2		—	0.2
Balance at December 31	$ 1,515.8		$ 37.6	$ 1,553.4

(1) Distributions of $35.2 million, received in the first quarter of 2017, were approved and recorded as a receivable from ATC in other current assets at December 31, 2016.

(2) Of this amount, $39.9 million was recorded as a receivable from ATC in other current assets at December 31, 2017.

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 required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC 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)	2019	2018	2017
Charges to ATC for services and construction	**$ 25.9**	$ 21.8	$ 17.1
Charges from ATC for network transmission services	**348.1**	338.1	349.3
Refund from ATC related to a FERC audit	**—**	22.0	—
Refund from ATC per FERC ROE order	**—**	—	28.3

As of December 31, 2019 and 2018, our balance sheets included the following receivables and payables for services received from or provided to ATC:

(in millions)	2019		2018	
Accounts receivable for services provided to ATC	**$ 3.5**		$ 3.4	
Accounts payable for services received from ATC	**29.0**		28.2	
Amounts due from ATC for transmission infrastructure upgrades	**2.8**	(1)	29.4	(2)

(1) In connection with WPS's construction of its two new solar projects, Badger Hollow I and Two Creeks, WPS was required to initially fund the construction of the transmission infrastructure upgrades needed for the new generation. ATC owns these transmission assets and will reimburse WPS for these costs after the new generation has been placed in service.

(2) In connection with UMERC's construction of the new natural gas-fired generation in the Upper Peninsula of Michigan, UMERC was required to initially fund the construction of the transmission infrastructure upgrades owned by ATC that were needed for the new generation. In the second quarter of 2019, ATC fully reimbursed UMERC for these costs.

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

(in millions)	Year Ended December 31 2019	2018	2017
Income statement data			
Operating revenues	**$ 744.4**	$ 690.5	$ 721.7
Operating expenses	**373.5**	358.7	345.0
Other expense, net	**110.5**	108.3	104.1
Net income	**$ 260.4**	$ 223.5	$ 272.6

(in millions)	December 31, 2019		December 31, 2018	
Balance sheet data				
Current assets	**$**	**84.7**	$	87.2
Noncurrent assets		**5,244.2**		4,928.8
Total assets	**$**	**5,328.9**	$	5,016.0
Current liabilities	**$**	**502.6**	$	640.0
Long-term debt		**2,312.8**		2,014.0
Other noncurrent liabilities		**298.9**		295.3
Shareholders' equity		**2,214.6**		2,066.7
Total liabilities and shareholders' equity	**$**	**5,328.9**	$	5,016.0

NOTE 21—SEGMENT INFORMATION

We use operating income to measure segment profitability and to allocate resources to our businesses. At December 31, 2019, 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 and non-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, and
    - 80% ownership interest in Upstream, located in Antelope County, Nebraska.

  See Note 2, Acquisitions, for more information on Bluewater, Bishop Hill III, Coyote Ridge, and Upstream.
- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, and PDL. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. In 2019, we sold certain PDL solar power generating facilities. See Note 3, Dispositions, for more information on these sales.

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, 2019, 2018, and 2017.

	Utility Operations								
2019 *(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	**$ 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**
Operating income (loss)	**1,189.6**	**291.9**	**65.3**	**1,546.8**	**—**	**366.6**	**(34.4)**	**(347.6)**	**1,531.4**
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**
Capital expenditures and asset acquisitions	**1,378.6**	**624.9**	**109.1**	**2,112.6**	**—**	**389.9**	**26.5**	**—**	**2,529.0**
Total assets *	**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**

* Total assets at December 31, 2019 reflect an elimination of $1,896.7 million for all lease activity between We Power and WE.

	Utility Operations								
2018 *(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	$ 5,794.7	$ 1,400.0	$ 438.2	$ 7,632.9	$ —	$ 37.9	$ 8.7	$ —	$ 7,679.5
Intersegment revenues	—	—	—	—	—	430.5	—	(430.5)	—
Other operation and maintenance	2,076.1	472.3	101.0	2,649.4	—	12.6	1.8	(393.3)	2,270.5
Depreciation and amortization	546.6	170.3	24.1	741.0	—	75.7	29.1	—	845.8
Operating income (loss)	800.2	255.8	68.8	1,124.8	—	365.8	(22.2)	—	1,468.4
Equity in earnings of transmission affiliates	—	—	—	—	136.7	—	—	—	136.7
Interest expense	200.7	51.2	8.7	260.6	0.3	63.7	125.8	(5.3)	445.1
Capital expenditures and asset acquisitions	1,466.1	547.1	103.6	2,116.8	—	260.6	39.7	—	2,417.1
Total assets *	23,407.0	6,483.3	1,147.9	31,038.2	1,665.3	3,227.2	959.6	(3,414.5)	33,475.8

* Total assets at December 31, 2018 reflect an elimination of $1,968.5 million for all lease activity between We Power and WE.

2017 *(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	$ 5,829.2	$ 1,355.5	$ 411.2	$ 7,595.9	$ —	$ 38.9	$ 13.7	$ —	$ 7,648.5
Intersegment revenues	—	—	—	—	—	446.3	—	(446.3)	—
Other operation and maintenance	1,923.2	464.2	101.1	2,488.5	—	7.3	1.4	(441.1)	2,056.1
Depreciation and amortization	523.9	152.6	24.8	701.3	—	71.4	25.9	—	798.6
Operating income (loss)	1,055.2	279.9	54.4	1,389.5	—	400.5	(13.9)	—	1,776.1
Equity in earnings of transmission affiliates	—	—	—	—	154.3	—	—	—	154.3
Interest expense	193.7	45.0	8.7	247.4	—	62.8	107.3	(1.8)	415.7
Capital expenditures	1,152.3	545.2	74.5	1,772.0	—	35.4	152.1	—	1,959.5
Total assets *	22,237.1	6,144.7	1,067.8	29,449.6	1,593.4	2,992.8	953.6	(3,398.9)	31,590.5

* Total assets at December 31, 2017 reflect an elimination of $2,038.1 million for all lease activity between We Power and WE.

NOTE 22—VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the entity's assets and liabilities. In addition, certain disclosures are required for significant interest holders in variable interest entities.

We assess our relationships with potential variable interest entities, such as our coal suppliers, natural gas suppliers, coal transporters, natural gas transporters, and other counterparties related to power purchase agreements, 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.

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 variable interest entity, 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, 2019 and 2018, our equity investment in ATC was $1,684.7 million and $1,625.3 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 variable interest entity, 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, 2019 and 2018, our equity investment in ATC Holdco was $36.1 million and $40.0 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 20, 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 Agreement

We have a power purchase agreement that represents a variable interest. This agreement is for 236 MWs of firm capacity from a natural gas-fired cogeneration facility, and we account for it as a finance lease. The agreement includes no minimum energy requirements over the remaining term of approximately two years. 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 power purchase agreement.

We have $22.4 million of required capacity payments over the remaining term of this agreement. We believe that the required capacity payments under this contract will continue to be recoverable in rates, and our maximum exposure to loss is limited to these capacity payments.

NOTE 23—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.

Our non-utility energy infrastructure generation facilities have obligations to distribute and sell electricity through long-term offtake agreements with their customers for all of the energy produced. These projects also enter into related easements and other agreements associated with the generating facilities.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2019, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	**Date Contracts Extend Through**	**Total Amounts Committed**	**2020**	**2021**	**2022**	**2023**	**2024**	**Later Years**
Electric utility:								
Nuclear	2033	$ 8,319.0	$ 475.1	$ 501.1	$ 531.2	$ 563.0	$ 596.8	$ 5,651.8
Coal supply and transportation	2024	983.2	306.9	255.7	223.4	196.5	0.7	—
Purchased power	2051	428.3	88.9	58.5	51.5	46.5	43.4	139.5
Natural gas utility:								
Supply and transportation	2048	1,652.3	344.8	285.5	224.6	131.2	70.8	595.4
Non-utility energy infrastructure:								
Purchased power	2061	173.6	7.7	8.8	8.6	8.8	8.9	130.8
Natural gas storage and transportation	2048	13.6	7.7	2.7	1.3	0.8	0.1	1.0
Total		$ 11,570.0	$ 1,231.1	$ 1,112.3	$ 1,040.6	$ 946.8	$ 720.7	$ 6,518.5

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, NO_x, 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, 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; and
- the remediation of former manufactured gas plant sites.

Air Quality

National Ambient Air Quality Standards

After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, which lowered the limit for ground-level ozone, creating a more stringent standard than the 2008 NAAQS. The EPA issued final nonattainment area designations in April 2018. The following counties within our service territories were designated as partial nonattainment: Door, Kenosha, Manitowoc, Northern Milwaukee/Ozaukee, and Sheboygan shorelines. This re-designation was challenged in the D.C. Circuit Court of Appeals in *Clean Wisconsin et al. v. U.S. Environmental Protection Agency.* Petitioners in that case have argued that additional portions of Milwaukee, Waukesha, Ozaukee, and Washington Counties (among others) should be designated as nonattainment for ozone. In November 2019, the D.C. Circuit Court of Appeals heard oral arguments for that case. A decision is expected in spring 2020, and we expect that any subsequent EPA re-designation, if necessary, would take place in mid-2021. We believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply. The State of Wisconsin is currently working with stakeholders, including us, in developing regulations for inclusion in the state implementation plan required by the rule.

Mercury and Air Toxics Standards

In December 2018, the EPA proposed to revise the Supplemental Cost Finding for the MATS rule as well as the CAA required RTR. The EPA was required by the United States Supreme Court to review both costs and benefits of complying with the MATS rule. After its review of costs, the EPA determined that it is not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. As a result, under the proposed rule, the emission standards and other requirements of the MATS rule first enacted in 2012 would remain in place. The EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112. The EPA also proposes that no revisions to MATS are warranted based on the results of the RTR. As a result, we do not expect the proposed rule to have a material impact on our financial condition or operations.

Climate Change

The ACE rule became effective in September 2019. This rule provides existing coal-fired generating units with standards for achieving GHG emission reductions. The rule was finalized in conjunction with two other separate and distinct rulemakings, (1) the repeal of the Clean Power Plan, and (2) revised implementing regulations for ACE, ongoing emissions guidelines, and all future emission guidelines for existing sources issued under CAA section 111(d). Every state's plan to implement ACE is required to focus on reducing GHG emissions by improving the efficiency of fossil-fueled power plants. The rule is being litigated in challenges brought in the D.C. Circuit Court of Appeals by 22 states (including Illinois, Michigan, Minnesota, and Wisconsin), local governments, and certain nongovernmental organizations. This litigation is proceeding, but has not yet been scheduled for oral argument. The WDNR is working with state utilities and has begun the process of developing the implementation plan with respect to the ACE rule.

In December 2018, the EPA proposed to revise the New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil-fueled power plants. The EPA determined that the BSER for new, modified, and reconstructed coal units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and subcritical steam conditions for smaller units. This proposed BSER would replace the determination from the previous rule, which identified BSER as partial carbon capture and storage.

In April 2019, we issued a climate report, which analyzes our GHG reduction goals with respect to international efforts to limit future global temperature increases to less than two degrees Celsius. We will evaluate potential GHG reduction pathways as climate change policies and relevant technologies evolve over time.

We continue to evaluate opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute toward long-term GHG emissions reductions. Our current plan is to work with our industry peers, environmental groups, public policy makers, and customers, with goals of reducing CO_2 emissions. In 2019, we met and exceeded our 2030 goal of reducing CO_2 emissions by 40% below 2005 levels, and are re-evaluating our longer-term CO_2 reduction goals. As a result of our generation reshaping plan, we retired approximately 1,800 MW of coal generation since the beginning of 2018, including the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units as well as the March 2019 retirement of the PIPP. See Note 6, Property, Plant, and Equipment, for more information. We also have a goal to decrease the rate of methane emissions from the natural gas distribution lines in our network by 30% per mile by the year 2030 from a 2011 baseline. We were over half way toward meeting that goal at the end of 2019.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. Based upon our analysis of the data, we reported CO_2 equivalent emissions of 21.8 million metric tonnes and 26.4 million metric tonnes to the EPA for 2019 and 2018, respectively. 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 analysis of the data, we reported CO_2 equivalent emissions of 29.4 million metric tonnes to the EPA for 2019 and 2018.

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 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.

We have received BTA determinations for OC 5 through OC 8, Weston Units 2, 3, and 4, and VAPP. Although we currently believe that existing technology at the PWGS satisfies the BTA requirements, final determinations will not be made until the discharge permit is renewed for this facility, which is expected to be in 2021. Until that time, we cannot determine what, if any, intake structure or operational modifications will be required to meet the new BTA requirements for this facility.

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 meet the regulation and do not expect to incur significant costs to comply with this regulation.

Steam Electric Effluent Limitation Guidelines

The EPA's final 2015 ELG rule took effect in January 2016. 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. As a result of past capital investments at WE and WPS, we believe our fleet is well positioned to meet the existing ELG regulations. 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 modifications to the BATW systems at Weston Unit 3 and OC 7 and OC 8. Also, one wastewater treatment system modification may be required for the wet FGD discharges from the six units that make up the OCPP and ERGS. Based on preliminary engineering, we estimate that compliance with the current rule will require $60 million in capital costs.

The ELG requirements for BATW and wet FGD systems are currently being re-evaluated by the EPA. In September 2017, the EPA issued a final rule (Postponement Rule) to postpone the earliest compliance date to November 1, 2020 for the BATW and wet FGD wastewater requirements while it reconsiders the ELG rule. The Postponement Rule left unchanged the latest ELG rule compliance date of December 31, 2023. In November 2019, the EPA Administrator signed the proposed ELG Reconsideration Rule to revise the treatment technology requirements related to BATW and wet FGD wastewaters at existing facilities. The EPA also proposed a provision that exempts facility owners from the new BATW and wet FGD requirements if a generating unit is retired by December 31, 2028. We expect the rule to be finalized in late 2020. In the meantime, we are currently evaluating what impact, if any, the proposed rule would have on our estimated compliance cost.

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)	**2019**	**2018**
Regulatory assets	**$ 685.5**	$ 687.1
Reserves for future environmental remediation	**589.2**	616.4

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, and met their compliance requirements by constructing various wind 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 requires 12.5% of the state's electric energy to come from renewables for years 2019 through 2020, and energy optimization (efficiency) targets up to 1% annually. The renewable requirement is increased to 15.0% for 2021. UMERC was in compliance with these requirements as of December 31, 2019. 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 effect 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, Property, Plant, and Equipment, for more information about the retirement of the Pulliam units. We plan to request termination of the WPS Consent Decree during 2020.

Joint Ownership Power Plants – Columbia and Edgewater

In December 2009, the EPA issued an NOV to Wisconsin Power and Light, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric, 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, Madison Gas and Electric, 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, Property, Plant, and Equipment, for more information about the retirement. WE paid an immaterial portion of the assessed penalty but has no further obligations under the Consent Decree.

NOTE 24—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31		
(in millions)	**2019**	**2018**	**2017**
Cash paid for interest, net of amount capitalized	**$ 485.9**	$ 441.5	$ 413.7
Cash paid (received) for income taxes, net	**(24.9)**	16.3	(5.2)
Significant non-cash investing and financing transactions:			
Accounts payable related to construction costs	**159.9**	65.9	169.2
Capital contributions from noncontrolling interest	**21.0**	—	—
Receivable related to corporate-owned life insurance proceeds	**—**	7.7	—
Portion of Bostco real estate holdings sale financed with note receivable *	**—**	—	7.0

* See Note 3, Dispositions, for more information on this sale.

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 includes the restricted cash we received when WECI acquired ownership interests in Bishop Hill III and Upstream during August 2018 and January 2019, respectively. This cash is restricted as it can only be used to pay for any remaining costs associated with the construction of these wind generation facilities. See Note 2, Acquisitions, for more information on the acquisitions of Bishop Hill III and Upstream.

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)	**2019**	**2018**	**2017**
Cash and cash equivalents	**$ 37.5**	$ 84.5	$ 38.9
Restricted cash included in other current assets	**—**	2.5	—
Restricted cash included in other long term assets	**44.8**	59.1	19.7
Cash, cash equivalents, and restricted cash	**$ 82.3**	$ 146.1	$ 58.6

NOTE 25—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

Due to the Tax Legislation, our regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $2,529 million that resulted from the revaluation of deferred taxes. The Tax Legislation also reduced the corporate federal tax rate from a maximum of 35% to a 21% rate, effective January 1, 2018. We have received written orders from the PSCW and the MPSC addressing the refunding of certain of these tax benefits to ratepayers in Wisconsin and Michigan, respectively. The ICC has approved the VITA in Illinois, and the MPUC addressed the impacts to MERC in its 2018 rate order. See the Variable Income Tax Adjustment Rider discussion and the 2018 Minnesota Rate Order discussion below for more information. A summary of the Wisconsin and Michigan orders is outlined below.

Wisconsin

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order required WE's and WPS's electric utility operations to use 80% and 40%, respectively, of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 20% and 60% at WE and WPS, respectively, was to be returned to electric customers in the form of bill credits. For our Wisconsin natural gas utility operations, the PSCW indicated that 100% of the current 2018 and 2019 tax benefits should be returned to natural gas customers in the form of bill credits. Regarding the net tax benefit associated with the revaluation of deferred taxes, amortization required in accordance with normalization accounting was used to reduce certain regulatory assets for our electric utilities and was deferred at our natural gas utilities. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes was addressed in the rate orders issued by the PSCW in December 2019. See the 2020 and 2021 Rates discussion below for more information.

Michigan

In February 2018, the MPSC issued an order requiring Michigan utilities to make three filings related to the Tax Legislation. The first of those filings, which was filed in March 2018, prospectively addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21%. MGU and UMERC proposed providing a volumetric bill credit, subject to reconciliation and true up. In May 2018, the MPSC issued orders approving settlements that resulted in volumetric bill credits for all of MGU's and UMERC's customers effective July 1, 2018. The bill credits will remain in effect until each company's next rate proceeding.

The second filing, which was filed in July 2018, addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21% from January 1, 2018 until July 1, 2018. MGU and UMERC proposed to return the tax savings from these months to customers via volumetric bill credits over multiple months. The MPSC issued orders approving settlements in September 2018. In accordance with the settlement orders, the savings were returned to MGU's and UMERC's customers via volumetric bill credits that were in effect from October 1, 2018 through December 31, 2018.

The third filing was filed in October 2018 and addressed the remaining impacts of the Tax Legislation on base rates – most notably the re-measurement of deferred tax balances. MGU and UMERC proposed providing a volumetric bill credit, subject to reconciliation and true up, to return these remaining impacts of the Tax Legislation to customers. The MPSC issued orders approving settlements in May 2019. The settlement orders provide for volumetric bill credits to MGU's and UMERC's customers effective June 1, 2019. The bill credits will remain in effect until each company's next rate proceeding.

WE, which served one retail electric customer in Michigan, reached a settlement with that customer. That settlement was approved by the MPSC in May 2018 and addressed all base rate impacts of the Tax Legislation, which were returned to the customer through bill credits.

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

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. On

December 19, 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 became effective January 1, 2020. The final orders reflect 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 reflect 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 will be amortized in each of 2020 and 2021. For WPS, approximately $11 million of tax benefits are being amortized in 2020 and approximately $39 million will be amortized in 2021. The unprotected deferred tax benefits related to the unrecovered balances of WE's recently retired plants and its SSR regulatory asset are being 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 is net of $21 million of refunds related to its 2018 earnings sharing mechanism. These refunds will be made to customers evenly over two years, with half being returned in 2020 and the remainder 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 reflect 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 will seek a financing order from the PSCW 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 related fees. The securitization will reduce the carrying costs for the $100 million, benefiting customers.

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 will be collected from customers over eight years.

All three Wisconsin utilities will continue having an earnings sharing mechanism through 2021. The earnings sharing mechanism was modified from its previous structure to one that is consistent with other Wisconsin investor-owned utilities. Under the new earnings sharing mechanism, if the utility earns above its authorized ROE: (i) the utility retains 100.0% of earnings for the first 25 basis points above the authorized ROE; (ii) 50.0% of the next 50 basis points is refunded to customers; and (iii) 100.0% of any remaining excess earnings is refunded to customers. In addition, the rate orders also require 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.

2018 and 2019 Rates

During April 2017, WE, WPS, and WG filed an application with the PSCW for approval of a settlement agreement they made with several of their commercial and industrial customers regarding 2018 and 2019 base rates. In September 2017, the PSCW issued an order that approved the settlement agreement, which froze base rates through 2019 for electric, natural gas, and steam customers of WE, WPS, and WG. Based on the PSCW order, the authorized ROE for WE, WPS, and WG remained at 10.2%, 10.0%, and 10.3%, respectively, and the capital cost structure for all of our Wisconsin utilities remained unchanged through 2019.

In addition to freezing base rates, the settlement agreement extended and expanded the electric real-time market pricing program options for large commercial and industrial customers and mitigated the continued growth of certain escrowed costs at WE during the base rate freeze period by accelerating the recognition of certain tax benefits. WE was flowing 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. While WE would typically follow the normalization accounting method and utilize the tax benefits of the deferred tax liabilities in rate-making as an offset to rate base, benefiting customers over time, the federal tax code does allow for passing these tax repair-related benefits to ratepayers much sooner using the flow through accounting method. 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 change to net income.

The agreement also allowed WPS to extend through 2019, the deferral for the revenue requirement of ReACT™ costs above the authorized $275.0 million level, and other deferrals related to WPS's electric real-time market pricing program and network transmission expenses.

Pursuant to the settlement agreement, WPS also agreed to adopt, beginning in 2018, the earnings sharing mechanism that had been in place for WE and WG since January 2016, and all three utilities agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if WE, WPS, or WG earned above its authorized ROE, 50% of the first 50 basis points of additional utility earnings were required to be refunded to customers. All utility earnings above the first 50 basis points were also required to be refunded to customers.

Liquefied Natural Gas Facilities

On November 1, 2019, WE and WG filed a joint application with the PSCW requesting approval for each company to construct its own LNG facility. If approved, each facility would provide one billion cubic feet of natural gas supply to meet 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 LNG facilities is targeted for the end of 2023.

Solar Generation Projects

On August 1, 2019, WE, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire an ownership interest in a proposed solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin. Once constructed, WE will own 100 MW of the output of this project. WE's share of the cost of this project is estimated to be $130 million. At its meeting on February 20, 2020, the PSCW approved the acquisition of this project. The approval is still subject to WE's receipt and review of a final written order from the PSCW. Commercial operation of Badger Hollow II is targeted for the end of 2021.

In May 2018, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire ownership interests in two solar projects in Wisconsin. Badger Hollow I is located in Iowa County, Wisconsin, and Two Creeks is located in Manitowoc County, Wisconsin. Once constructed, WPS will own 100 MW of the output of each project for a total of 200 MW. WPS's share of the cost of both projects is estimated to be $256 million. The PSCW approved the acquisition of these two projects in April 2019. Commercial operation of both projects is targeted for the end of 2020.

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The FERC approved the transaction in January 2018, and the PSCW approved the transaction in March 2018. The transaction closed in April 2018. See Note 2, Acquisitions, for more information.

Natural Gas Storage Facilities in Michigan

In January 2017, we signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for the natural gas operations of WE, WPS, and WG. As a result of this agreement, WE, WPS, and WG filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WE, WPS, and WG requested that the PSCW review and confirm the reasonableness and prudency of their potential long-term storage service agreements and interstate natural gas transportation contracts related to the storage facilities. WE, WPS, and WG also requested approval to amend our Affiliated Interest Agreement to ensure WBS and our other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and we acquired Bluewater on June 30, 2017. In September 2017, WE, WPS, and WG entered into the long-term service agreements for the natural gas storage, which were approved by the PSCW in November 2017. See Note 2, Acquisitions, for more information.

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

Illinois Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP, which were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program, and issued a final order in January 2018. The order did not have a significant impact on PGL's existing SMP design and execution. An appeal related to the final order was filed by the Illinois AG in April 2018. In June 2019, the Illinois Appellate Court issued its ruling affirming the ICC’s final order. The appeal period has since expired for this ruling.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides PGL 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 September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2019, PGL filed its 2018 reconciliation with the ICC, which, along with the 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, 2019, all amounts had been refunded.

As of December 31, 2019, 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.

Variable Income Tax Adjustment Rider

In April 2018, the ICC approved the VITA proposed by PGL and NSG. The VITA recovers or refunds changes in income tax expense resulting from differences in income tax rates and amortization of deferred tax excesses and deficiencies (in accordance with the Tax Legislation) from the amounts used in the last PGL and NSG rate case, effective January 25, 2018.

Minnesota Energy Resources Corporation

2018 Minnesota 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 Application

On February 3, 2020, MGU provided notification to the MPSC of its intent to file an application requesting an increase to its natural gas rates. The application is expected to be filed in March 2020 and to request new rates be effective January 1, 2021. MGU is currently in the process of evaluating its rate request.

Upper Michigan Energy Resources Corporation

Formation of Upper Michigan Energy Resources Corporation

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility in the Upper Peninsula of Michigan, and UMERC became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets, previously held by WE and WPS, located in the Upper Peninsula of Michigan.

In August 2016, we entered into an agreement with Tilden under which Tilden agreed to purchase electric power from UMERC for its iron ore mine for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. In October 2017, the MPSC approved both the agreement with Tilden and UMERC's application for a certificate of necessity to begin construction of the proposed generation.

On March 31, 2019, UMERC's new generation solution in the Upper Peninsula began commercial operation, and the agreement with Tilden became effective. The cost of the new units was approximately $242 million ($255 million with AFUDC), 50% of which is expected to be recovered from Tilden, with the remaining 50% expected to be recovered from UMERC's other utility customers. Tilden remained a customer of WE until the new generation began commercial operation.

NOTE 26—OTHER INCOME, NET

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

(in millions)	2019	2018	2017
AFUDC – Equity	**$ 14.4**	$ 15.2	$ 11.4
Non-service components of net periodic benefit costs	**36.2**	26.0	9.1
Gains (losses) from investments held in rabbi trust	**21.2**	(1.8)	21.5
Other, net	**30.4**	30.9	31.7
Other income, net	**$ 102.2**	$ 70.3	$ 73.7

NOTE 27—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019					
Operating revenues	**$ 2,377.4**	**$ 1,590.2**	**$ 1,608.0**	**$ 1,947.5**	**$ 7,523.1**
Operating income	**542.8**	**314.6**	**310.9**	**363.1**	**1,531.4**
Net income attributed to common shareholders	**420.1**	**235.7**	**234.3**	**243.9**	**1,134.0**
Earnings per share *					
Basic	**$ 1.33**	**$ 0.75**	**$ 0.74**	**$ 0.77**	**$ 3.60**
Diluted	**1.33**	**0.74**	**0.74**	**0.77**	**3.58**
2018					
Operating revenues	$ 2,286.5	$ 1,672.5	$ 1,643.7	$ 2,076.8	$ 7,679.5
Operating income	545.1	330.8	302.7	289.8	1,468.4
Net income attributed to common shareholders	390.1	231.0	233.2	205.0	1,059.3
Earnings per share *					
Basic	$ 1.24	$ 0.73	$ 0.74	$ 0.65	$ 3.36
Diluted	1.23	0.73	0.74	0.65	3.34

* Earnings per share for the individual quarters may not total the year ended earnings per share amount because of changes to the average number of shares outstanding and changes in incremental issuable shares throughout the year.

NOTE 28—NEW ACCOUNTING PRONOUNCEMENTS

Financial Instruments 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. The amendment requires entities to consider a broader range of information to estimate expected credit losses, which may result in earlier recognition of loss. 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.

Because our exposure to credit losses for many of our regulated utility customers is mitigated by regulatory mechanisms we have in place, the noncash cumulative effect adjustment we recorded to retained earnings on January 1, 2020, as a result of our adoption of this standard, was not significant. The most significant impact of implementing this ASU will be in the form of additional disclosures that will be required in our quarterly report on Form 10-Q for the quarter ended March 31, 2020. These disclosures are intended to provide information that will help users of our financial statements analyze our exposure to credit risk and understand how we estimate our allowance for credit losses.

Cloud Computing

In August 2018, the FASB issued ASU 2018-15, Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The adoption of ASU 2018-15, effective January 1, 2020, did not have a significant impact on our financial statements.

Disclosure Requirements for Defined Benefit Plans

In August 2018, the FASB issued ASU 2018-14, Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans. The pronouncement modifies the disclosure requirements for defined benefit pension and other postretirement benefit plans. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The modifications affect annual period disclosures and must be applied on a retrospective basis to all periods presented. The guidance will be effective for annual reporting periods ending after December 15, 2020, with early adoption permitted. We are currently evaluating the effects of this pronouncement on the notes to our financial statements.

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, 2019.

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 2019 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

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors – Terms Expiring in 2021," "Governance – Board Committees – Audit and Oversight," and "Delinquent Section 16(a) Reports," in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 6, 2020 (the "2020 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 2020 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 2020 Annual Meeting Proxy Statement.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2019:

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	3,249,918	$ 54.98	26,456,888 *
Equity Compensation Plans Not Approved by Security Holders	N/A	N/A	N/A
Total	3,249,918	$ 54.98	26,456,888

* 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 "Proposal 1: Election of Directors – Terms Expiring in 2021 – Director Independence" and "Governance" in the 2020 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 2020 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 October 20, 2016. (Exhibit 3.1 to WEC Energy Group's 10/20/16 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.
	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 Wisconsin Energy Corporation'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. 11 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of September 7, 2011. (Exhibit 4.1 under File No. 1-1245, WE's 09/07/11 Form 8-K.)
	4.11*	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.)
	4.12*	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.)
	4.13*	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.)
	4.14*	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.)
	4.15*	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.)
	4.16*	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.)
	4.17*	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, dated 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, dated as of June 4, 2015. (Exhibit 4.1 to Wisconsin Energy Corporation's 06/04/15 Form 8-K.)
4.21*	Securities Resolution No. 7 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of June 4, 2018. (Exhibit 4.1 to WEC Energy Group's 06/04/18 Form 8-K.)
4.22*	Securities Resolution No. 8 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of March 4, 2019. (Exhibit 4.1 to WEC Energy Group's 03/04/19 Form 8-K.)
4.23*	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).
4.24*	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).
4.25*	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).
4.26*	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).
4.27*	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).
4.28*	Twelfth Supplemental Indenture, dated as of November 21, 2018, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 21, 2018) (File No. 1-3016).
4.29*	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).
	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.)**
10.6*	WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.**

Number	Exhibit
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 Gale E. Klappa, dated as of December 20, 2019. (Exhibit 10.1 to WEC Energy Group's 12/23/2019 Form 8-K.)**
10.11*	Letter Agreement by and between Gale E. Klappa and WEC Energy Group, Inc., dated as of January 17, 2019. (Exhibit 10.1 to WEC Energy Group's 01/22/2019 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 Frederick D. Kuester, dated as of February 23, 2018. (Exhibit 10.1 to WEC Energy Group's 03/31/2018 Form 10-Q.)**
10.16*	WEC Energy Group 1993 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*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q.)**
10.18*	2016 WEC Energy Group Terms and Conditions Governing Director Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.24 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.19*	Director Restricted Stock Award Terms and Conditions under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/01/16 Form 8-K.)**
10.20*	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.)**
10.21*	2016 WEC Energy Group Restricted Stock Award Terms and Conditions governing awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.27 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.22*	Wisconsin Energy Corporation Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan, approved December 4, 2014. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/04/14 Form 8-K.)**
10.23*	2016 WEC Energy Group Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.29 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.24*	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).)
10.25*	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).)

Number	Exhibit
	10.26* 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.)
	10.27* 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.)
	10.28* 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.)
	10.29* 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.)
	10.30* 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.)**
	10.31* 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.)**
	10.32* PELLC Directors Deferred Compensation Plan as amended and restated April 7, 2004. (Exhibit 10(a) under File No. 1-5540, PELLC's 06/30/04 Form 10-Q.)**
	10.33* Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of August 13, 2003. (Exhibit 10(a) under File No. 1-5540, PELLC's 09/30/03 Form 10-Q.)**
	10.34* Amendment Number One to the Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of July 24, 2006. (Exhibit 10(e) under File No. 1-5540, PELLC's 09/30/06 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.
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.

Number	Exhibit	
101	**Interactive Data File**	
	101.INS	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
	101.SCH	Inline XBRL Taxonomy Extension Schema
	101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase
	101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase
	101.LAB	Inline XBRL Taxonomy Extension Label Linkbase
	101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	**Cover Page Interactive Date File (formatted as Inline XBRL and contained in Exhibit 101)**	

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE I – CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. INCOME STATEMENTS

Year Ended December 31 *(in millions)*	**2019**	**2018**	**2017**
Operating expenses	**$ 4.7**	$ 5.0	$ 6.0
Equity in earnings of subsidiaries	**1,210.5**	1,108.3	1,234.7
Other income, net	**6.3**	6.8	2.1
Interest expense	**122.3**	104.1	82.0
Income before income taxes	**1,089.8**	1,006.0	1,148.8
Income tax benefit	**44.2**	53.3	54.9
Net income attributed to common shareholders	**$ 1,134.0**	$ 1,059.3	$ 1,203.7

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 ***(in millions)***	**2019**	2018	2017
Net income attributed to common shareholders	**$ 1,134.0**	$ 1,059.3	$ 1,203.7
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Net derivative losses, net of tax benefits of $1.3, $0.8, and $0.0, respectively	**(3.5)**	(2.1)	—
Reclassification of net gains to net income, net of tax	**(0.8)**	(1.2)	(1.3)
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	1.6	—
Cash flow hedges, net	**(4.3)**	(1.7)	(1.3)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**0.4**	(0.9)	(0.1)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.2**	0.2	0.2
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	(0.3)	—
Defined benefit plans, net	**0.6**	(1.0)	0.1
Other comprehensive income (loss) from subsidiaries, net of tax	**2.2**	(2.8)	1.2
Other comprehensive loss, net of tax	**(1.5)**	(5.5)	—
Comprehensive income attributed to common shareholders	**$ 1,132.5**	$ 1,053.8	$ 1,203.7

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

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C. BALANCE SHEETS

At December 31 *(in millions)*	2019	2018
Assets		
Current assets		
Cash and cash equivalents	**$ 0.5**	$ 32.8
Accounts receivable from related parties	**0.7**	4.0
Notes receivable from related parties	**22.5**	71.0
Prepaid taxes	**46.5**	—
Other	**—**	0.6
Current assets	**70.2**	108.4
Long-term assets		
Investments in subsidiaries	**13,433.1**	12,682.5
Notes receivable from UMERC	**—**	150.0
Other	**23.0**	31.8
Long-term assets	**13,456.1**	12,864.3
Total assets	**$ 13,526.3**	$ 12,972.7
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 334.7**	$ 548.4
Current portion of long-term debt	**400.0**	—
Accounts payable to related parties	**2.5**	7.7
Notes payable to related parties	**489.3**	398.9
Other	**17.9**	14.0
Current liabilities	**1,244.4**	969.0
Long-term liabilities		
Long-term debt	**2,141.6**	2,190.8
Other	**26.9**	24.0
Long-term liabilities	**2,168.5**	2,214.8
Common shareholders' equity	**10,113.4**	9,788.9
Total liabilities and equity	**$ 13,526.3**	$ 12,972.7

The accompanying notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

D. STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2019	2018	2017
Operating activities			
Net income attributed to common shareholders	**$ 1,134.0**	$ 1,059.3	$ 1,203.7
Reconciliation to cash provided by operating activities			
Equity income in subsidiaries, net of distributions	**(475.2)**	(419.4)	(686.1)
Deferred income taxes	**9.1**	14.4	89.5
Change in –			
Accounts receivable from related parties	**3.3**	(2.1)	(0.1)
Prepaid taxes	**(46.5)**	17.5	28.4
Accounts payable to related parties	**(5.2)**	4.6	(0.5)
Other current liabilities	**1.5**	4.7	(1.4)
Other, net	**7.0**	5.6	0.9
Net cash provided by operating activities	**628.0**	684.6	634.4
Investing activities			
Acquisition of Bluewater	**—**	—	(226.0)
Capital contributions to subsidiaries	**(602.3)**	(448.7)	(173.4)
Return of capital from subsidiaries	**337.3**	290.2	—
Short-term notes receivable from related parties, net	**48.5**	(6.9)	167.8
Issuance of long-term notes receivable from UMERC	**—**	(100.0)	(50.0)
Redemption of long-term notes receivable from UMERC	**150.0**	—	—
Other, net	**(0.6)**	6.4	4.5
Net cash used in investing activities	**(67.1)**	(259.0)	(277.1)
Financing activities			
Exercise of stock options	**67.0**	29.1	30.8
Purchase of common stock	**(140.1)**	(72.4)	(71.3)
Dividends paid on common stock	**(744.5)**	(697.3)	(656.5)
Issuance of long-term debt	**350.0**	600.0	—
Retirement of long-term debt	**—**	(300.0)	—
Change in short-term debt	**(213.7)**	53.6	173.0
Short-term notes payable to related parties, net	**90.4**	(6.2)	169.5
Other, net	**(2.3)**	(3.6)	—
Net cash used in financing activities	**(593.2)**	(396.8)	(354.5)
Net change in cash and cash equivalents	**(32.3)**	28.8	2.8
Cash and cash equivalents at beginning of year	**32.8**	4.0	1.2
Cash and cash equivalents at end of year	**$ 0.5**	$ 32.8	$ 4.0

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)	2019	2018	2017
WE	**$ 360.0**	$ 310.0	$ 240.0
We Power	**192.5**	223.0	181.0
ATC Holding	**87.4**	105.8	82.6
WG	**60.0**	50.0	45.0
WECI	**25.4**	—	—
UMERC	**10.0**	—	—
Wisvest	**—**	0.1	—
Total	**$ 735.3**	$ 688.9	$ 548.6

NOTE 3—LONG-TERM DEBT

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2019:

(in millions)	
2020	**$ 400.0**
2021	**600.0**
2022	**350.0**
2023	**—**
2024	**—**
Thereafter	**1,200.0**
Total	**$ 2,550.0**

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:

	2019		2018	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term notes receivable from UMERC	**$ —**	**$ —**	$ 150.0	$ 145.5
Long-term debt, including current portion	**2,541.6**	**2,619.4**	2,190.8	2,132.8

The fair values of our long-term notes receivable and long-term debt are categorized within Level 2 of the fair value hierarchy.

NOTE 5—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2019	2018	2017
Cash paid for interest	**$ 117.7**	$ 102.9	$ 82.5
Cash received for income taxes, net	**(4.9)**	(85.9)	(169.9)
Significant non-cash investing and financing transactions:			
Issuance of short-term note receivable to Bluewater	**—**	—	115.0
Issuance of short-term note receivable to UMERC	**—**	—	40.5
Settlement of short-term note payable with Wisvest	**—**	0.9	—
Settlement of short-term note payable with Bostco	**—**	—	4.8

NOTE 6—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)	2019	2018
Wispark	**$ 13.5**	$ 28.5
UMERC	**9.0**	42.5
Total	**$ 22.5**	$ 71.0

NOTE 7—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)	2019	2018
WBS	**$ 168.9**	$ 123.5
Integrys	**166.9**	139.5
WECC	**111.7**	110.3
Bluewater Gas Storage	**41.8**	25.6
Total	**$ 489.3**	$ 398.9

SCHEDULE II
WEC ENERGY GROUP, INC.
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts ***(in millions)***	**Balance at Beginning of Period**	**Expense (1)**	**Deferral**	**Net Write-offs (2)**	**Balance at End of Period**
December 31, 2019	**$ 149.2**	**$ 85.8**	**$ 11.4**	**$ (106.4)**	**$ 140.0**
December 31, 2018	143.2	94.7	(5.5)	(83.2)	149.2
December 31, 2017	108.0	96.7	16.4	(77.9)	143.2

(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/ J. KEVIN FLETCHER

Date: February 27, 2020

J. Kevin Fletcher
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/ J. KEVIN FLETCHER	February 27, 2020
J. Kevin Fletcher, President and Chief Executive Officer, and Director -- Principal Executive Officer	
/s/ SCOTT J. LAUBER	February 27, 2020
Scott J. Lauber, Senior Executive Vice President and Chief Financial Officer -- Principal Financial Officer	
/s/ WILLIAM J. GUC	February 27, 2020
William J. Guc, Vice President and Controller -- Principal Accounting Officer	
/s/ GALE E. KLAPPA	February 27, 2020
Gale E. Klappa, Executive Chairman and Director	
/s/ BARBARA L. BOWLES	February 27, 2020
Barbara L. Bowles, Director	
/s/ ALBERT J. BUDNEY, JR.	February 27, 2020
Albert J. Budney, Jr., Director	
/s/ PATRICIA W. CHADWICK	February 27, 2020
Patricia W. Chadwick, Director	
/s/ CURT S. CULVER	February 27, 2020
Curt S. Culver, Director	
/s/ DANNY L. CUNNINGHAM	February 27, 2020
Danny L. Cunningham, Director	
/s/ WILLIAM M. FARROW, III	February 27, 2020
William M. Farrow, III, Director	
/s/ THOMAS J. FISCHER	February 27, 2020
Thomas J. Fischer, Director	
/s/ MARIA C. GREEN	February 27, 2020
Maria C. Green, Director	
/s/ HENRY W. KNUEPPEL	February 27, 2020
Henry W. Knueppel, Director	
/s/ THOMAS K. LANE	February 27, 2020
Thomas K. Lane, Director	
/s/ ULICE PAYNE, JR.	February 27, 2020
Ulice Payne, Jr., Director	
/s/ MARY ELLEN STANEK	February 27, 2020
Mary Ellen Stanek, Director	

Exhibit 4.2

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

This summary highlights selected information about the capital stock of WEC Energy Group, Inc. ("WEC Energy Group," "we" or "our") and may not contain all of the information that is important to you. This summary does not purport to be exhaustive and is qualified in its entirety by reference to our Restated Articles of Incorporation (the "Articles of Incorporation") and our Bylaws (the "Bylaws").

General

The authorized capital stock of WEC Energy Group, Inc. consists of 325,000,000 shares of common stock, $.01 par value per share (the "Common Stock") and 15,000,000 shares of preferred stock, $.01 par value per share (the "Preferred Stock").

Preferred Stock

Under the Articles of Incorporation, the WEC Energy Group Board of Directors (the "Board") is authorized to divide the Preferred Stock into series, to issue shares of any series and, within the limitations set forth in the Articles of Incorporation or prescribed by law, to fix and determine the relative rights and preferences of the shares of any series so established, including the dividend rate, redemption price and terms, amount payable upon liquidation, and any sinking fund provisions, conversion privileges and voting rights.

Common Stock

The holders of Common Stock are entitled to receive such dividends as the Board may from time to time declare, subject to any rights of holders of Preferred Stock, if any is issued. Each holder of Common Stock is entitled to one vote per share on each matter submitted to a vote at a meeting of shareholders, subject to any class or series voting rights of holders of any Preferred Stock. The holders of Common Stock are not entitled to cumulate votes for the election of directors. In the event of any liquidation, dissolution or winding-up of WEC Energy Group, the holders of Common Stock, subject to any rights of the holders of any Preferred Stock, will be entitled to receive the remainder, if any, of the assets of WEC Energy Group after the discharge of its liabilities. Holders of Common Stock are not entitled to preemptive rights to subscribe for or purchase any part of any new or additional issue of stock or securities convertible into stock. The Common Stock does not have any redemption provisions or conversion rights.

WEC Energy Group's ability to pay dividends primarily depends on the availability of funds received from our utility subsidiaries and our non-utility 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. All of our utility subsidiaries, with the exception of Upper Michigan Energy Resources Corporation and Michigan Gas Utilities Corporation, are prohibited from loaning funds to us, either directly or indirectly.

All of the outstanding shares of our common stock are fully paid and non-assessable.

Certain Anti-Takeover Provisions in our Articles of Incorporation and Bylaws

The Articles of Incorporation and Bylaws contain provisions which may have the effect of discouraging persons from acquiring large blocks of WEC Energy Group stock or delaying or preventing a change in control of WEC Energy Group. The material provisions which may have such an effect are:

- an anti-greenmail provision prohibiting the purchase of shares of Common Stock at a market premium from any person whom the Board believes to be a beneficial owner of more than 5% of the outstanding shares of Common Stock unless such holder owned the shares for at least two years, the purchase was approved by a majority of the combined voting power of the shareholders, or the purchase is pursuant to a tender offer to all holders of Common Stock on the same terms;

- a provision permitting removal of a director without cause only by at least an 80% shareholder vote;

- authorization for the Board, subject to any required regulatory approval, to issue Preferred Stock in series and to fix rights and preferences of the series, including, among other things, whether, and to what extent, the shares of any series will have voting rights and the extent of the preferences of the shares of any series with respect to dividends and other matters;

- advance notice procedures with respect to shareholder nominations of directors or shareholder proposals at a meeting of shareholders; and

- provisions permitting amendment of some of these and related provisions only by at least an 80% shareholder vote at a meeting.

Anti-Takeover Effects of Wisconsin Law

Wisconsin law, under which we are incorporated, contains certain provisions that may have antitakeover effects, The description set forth below is intended as a summary only. For complete information you should review the applicable provisions of the Wisconsin Business Corporation Law and Section 196.795 of the Wisconsin Statutes, Wisconsin's public utility holding company law ("Wisconsin Public Utility Holding Company Law").

Control Share Acquisitions. Wisconsin law provides that, unless a corporation's articles of incorporation provide otherwise, or otherwise specified by the board of directors, the voting power of shares of a "resident domestic corporation" such as WEC Energy Group held by any person (including two or more persons acting as a group) in excess of 20% of the voting power in the election of directors is limited (in voting on any matter) to 10% of the full voting power of those shares. This restriction does not apply to shares acquired directly from a resident domestic corporation, or in certain specified transactions, or incident to a transaction in which shareholders have approved restoration of the full voting power of the otherwise restricted shares. WEC Energy Group has opted out of this statutory provision in its Articles of Incorporation.

Anti-Greenmail Provisions. Wisconsin law restricts the ability of certain publicly held corporations, such as WEC Energy Group, to repurchase voting shares at above market value from certain large shareholders, absent approval from the shareholders as a whole, unless an identical or better offer to purchase is made to all owners of voting shares and securities which may be converted into voting shares. These provisions apply during a takeover offer to purchases of more than 5% of the corporation's shares from a person or group that holds more than 3% of the corporation's voting shares and has held the shares for less than two years.

Wisconsin law also provides that shareholder approval is required for the corporation during a takeover offer to sell or option assets of the corporation which amount to at least 10% of the market value of the corporation, unless the corporation has at least three independent directors (directors who are not officers or employees) and a majority of the independent directors vote not to have this provision apply to the corporation.

The Articles of Incorporation require an 80% shareholder vote for any amendment to the Articles of Incorporation that would have the effect of opting out of the provisions described above.

Fair Price Provisions. Wisconsin law provides that in addition to any approval otherwise required, certain mergers, share exchanges or sales, leases, exchanges or other dispositions involving a resident domestic corporation, such as WEC Energy Group, and any significant shareholder are subject to a super-majority vote of shareholders unless certain fair price standards have been met. For this purpose a significant shareholder is defined as either a 10% shareholder or an affiliate of the resident domestic corporation who was a 10% shareholder at any time within the preceding two years. The super-majority vote that is required by the statute consists of:

- approval of 80% of the total voting power of the corporation, and
- approval of at least 66 2/3% of the voting power not beneficially owned by the significant shareholder or its affiliates or associates.

However, a supermajority vote is not required if the following "fair price" standards are satisfied:

- the consideration is in cash or in the form of consideration used to acquire the greatest number of shares, and
- the amount of the consideration equals the greater of:

(a) the highest price paid by the significant shareholder within the prior two-year period;

(b) in the case of a tender offer, the market value of the shares on the date the significant shareholder commences the tender offer; or

(c) the highest liquidation or dissolution distribution to which the shareholders would be entitled.

The Articles of Incorporation require an 80% shareholder vote for any amendment to the Articles of Incorporation that would have the effect of opting out of the fair price provisions.

Business Combination Provisions. Wisconsin law restricts resident domestic corporations, such as WEC Energy Group, from engaging in specified business combinations involving an "interested stockholder" or an affiliate or associate of an interested stockholder. For this purpose an "interested stockholder" is a shareholder who beneficially owns at least 10% of the voting power of the outstanding stock of the resident domestic corporation, or is an affiliate or associate of the resident domestic corporation and beneficially owned at least 10% of the voting power of the then outstanding stock within the preceding three years. The specified business combinations
include:

- a merger or statutory share exchange;

- a sale or other disposition of assets having a market value equal to at least 5% of the market value of the assets or outstanding stock of the corporation or representing at least 10% of its earning power or income;

- the issuance or transfer of stock or rights to purchase stock with a market value equal to at least 5% of the outstanding stock;

- the adoption of a plan or proposal for liquidation or dissolution;

- receipt by the interested stockholder or the interested stockholder's affiliates or associates of a disproportionate direct or indirect benefit of a loan or other financial benefit provided by or through the resident domestic corporation or its subsidiaries; or

- certain other transactions that have the direct or indirect effect of materially increasing the proportionate share of voting stock beneficially owned by the interested stockholder or the interested stockholder's affiliates or associates.

For a period of three years following the date that the interested stockholder becomes an interested stockholder, the resident domestic corporation is prohibited from engaging in any of the specified transactions with an interested stockholder unless the specified transaction or the purchase of stock by the interested stockholder is approved by the board of directors of the resident domestic corporation before the share acquisition date. Following the three year period, a specified transaction is permitted only if:

- the acquisition of shares by the interested stockholder was approved by the board of directors of the resident domestic corporation before the share acquisition date;

- the specified transaction is approved by a majority of the voting stock of the resident domestic corporation that is not owned by the interested stockholder; or

- the consideration to be received by the corporation's shareholders satisfies the "fair price" provisions of the statute as to form and amount.

Wisconsin Public Utility Holding Company Provisions. The Wisconsin Public Utility Holding Company Law provides that no person may take, hold or acquire, directly or indirectly, more than 10% of the outstanding voting securities of a public utility holding company, with the unconditional power to vote those securities, unless the PSCW has determined that the acquisition is in the best interests of utility consumers, investors and the public. Persons acquiring 10% or more of the voting securities of WEC Energy Group are subject to the provisions of the statute.

Exhibit 21.1

WEC ENERGY GROUP, INC.
SUBSIDIARIES AS OF DECEMBER 31, 2019

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, 2019:

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%
Bishop Hill Energy III Holdings LLC	Delaware	90%
Bishop Hill Energy III LLC	Delaware	100%
Coyote Ridge Wind, LLC	Oregon	80%
Upstream Wind Energy Holdings, LLC	Delaware	80%
Upstream Wind Energy LLC	Delaware	100%
WEC Investments, LLC	Delaware	100%
Wisconsin Electric Power Company	Wisconsin	100%
Wisconsin Energy Capital Corporation	Wisconsin	100%
Wisconsin Energy Services, LLC	Wisconsin	100%
State Energy Services, LLC	Wisconsin	50%
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, 2019. Indirectly owned subsidiaries are listed under the subsidiaries through which WEC Energy Group, Inc. holds ownership.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-221033 and 333-225349 on Form S-3 and Registration Statement Nos. 333-213589, 333-161151 and 333-177572 on Form S-8 of our reports dated February 27, 2020, relating to the consolidated financial statements and financial statement schedules of WEC Energy Group, Inc. and subsidiaries (the “Company”), and the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2019.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 27, 2020

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, J. Kevin Fletcher, 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 27, 2020

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
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, 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 27, 2020

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior 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, 2019, as filed with the Securities and Exchange Commission on February 27, 2020 (the "Report"), I, J. Kevin Fletcher, 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/ J. KEVIN FLETCHER

J. Kevin Fletcher
President and Chief Executive Officer
February 27, 2020

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, 2019, as filed with the Securities and Exchange Commission on February 27, 2020 (the "Report"), I, Scott J. Lauber, Senior 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/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President and Chief Financial Officer
February 27, 2020