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UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D. C. 20549

**FORM 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2017

**OR**

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

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

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

| Title of Each Class           | Name of Each Exchange on Which Registered |
|-------------------------------|---|
| Common Stock, \$.01 Par Value | 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

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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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post such files).

Yes  No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or 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  (Do not check if a smaller reporting company)

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 \$19.4 billion based upon the reported closing price of such securities as of June 30, 2017.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2018):

Common Stock, \$.01 par value, 315,544,495 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 3, 2018, are incorporated by reference into Part III hereof.

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**WEC ENERGY GROUP, INC.**  
**ANNUAL REPORT ON FORM 10-K**  
**For the Year Ended December 31, 2017**  
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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  |
| Bluewater  | Bluewater Natural Gas Holding, LLC   |
| Bostco     | Bostco LLC   |
| ERGSS      | Elm Road Generating Station Supercritical, LLC                             |
| Integrlys  | Integrlys Holding, Inc. (previously known as Integrlys Energy Group, Inc.) |
| ITF        | Integrlys Transportation Fuels, LLC  |
| MERC       | Minnesota Energy Resources Corporation                                     |
| MGU        | Michigan Gas Utilities Corporation   |
| NSG        | North Shore Gas Company  |
| PDL        | WPS Power Development, LLC   |
| PELLC      | Peoples Energy, LLC  |
| PGL        | The Peoples Gas Light and Coke Company                                     |
| UMERC      | Upper Michigan Energy Resources Corporation                                |
| WBS        | WEC Business Services LLC  |
| WE         | Wisconsin Electric Power Company   |
| We Power   | W.E. Power, LLC  |
| WECC       | Wisconsin Energy Capital Corporation                                       |
| 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                  |
| IRS  | United States Internal Revenue Service        |
| MDEQ | Michigan Department of Environmental Quality  |
| MPSC | Michigan Public Service Commission            |
| MPUC | Minnesota Public Utilities Commission         |
| PSCW | Public Service Commission of Wisconsin        |
| SEC  | Securities and Exchange Commission            |
| WDNR | Wisconsin Department of Natural Resources     |

### Accounting Terms

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



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**Environmental Terms**

|                 |  |
|-----------------|--|
| Act 141         | 2005 Wisconsin Act 141                 |
| CAA             | Clean Air Act                          |
| CO <sub>2</sub> | Carbon Dioxide                         |
| CPP             | Clean Power Plan                       |
| CSAPR           | Cross-State Air Pollution Rule         |
| GHG             | Greenhouse Gas                         |
| NAAQS           | National Ambient Air Quality Standards |
| NOV             | Notice of Violation                    |
| NO <sub>x</sub> | Nitrogen Oxide                         |
| SO <sub>2</sub> | Sulfur Dioxide                         |

**Measurements**

|      |                         |
|------|-------------------------|
| Dth  | Dekatherm               |
| MDth | One thousand Dekatherms |
| MW   | Megawatt                |
| MWh  | Megawatt-hour           |

**Other Terms and Abbreviations**

|                               |   |
|-------------------------------|---|
| 2006 Junior Notes             | Integrys's 2006 Junior Subordinated Notes Due 2066  |
| 2007 Junior Notes             | WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067  |
| ALJ                           | Administrative Law Judge  |
| ARRs                          | Auction Revenue Rights  |
| CNG                           | Compressed Natural Gas  |
| Compensation Committee        | Compensation Committee of the Board of Directors  |
| DATC                          | Duke-American Transmission Company  |
| 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  |
| Exchange Act                  | Securities Exchange Act of 1934, as amended   |
| FTRs                          | Financial Transmission Rights   |
| GCRM                          | Gas Cost Recovery Mechanism   |
| LMP                           | Locational Marginal Price   |
| MCCP                          | Milwaukee County Power Plant  |
| Merger Agreement              | Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys Energy Group, Inc. and Wisconsin Energy Corporation |
| MISO                          | Midcontinent Independent System Operator, Inc.  |
| MISO Energy Markets           | MISO Energy and Operating Reserves Market   |
| NYMEX                         | New York Mercantile Exchange  |
| OCCP                          | 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   |
| PWGS                          | Port Washington Generating Station  |
| PWGS 1                        | Port Washington Generating Station Unit 1   |
| PWGS 2                        | Port Washington Generating Station Unit 2   |



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|                 |  |
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| QIP             | Qualifying Infrastructure Plant              |
| ROE             | Return on Equity                             |
| RTO             | Regional Transmission Organization           |
| SMP             | Natural Gas System Modernization Program     |
| SMRP            | System Modernization and Reliability Project |
| SSR             | System Support Resource                      |
| Supreme Court   | United States Supreme Court                  |
| Tax Legislation | Tax Cuts and Jobs Act of 2017                |
| Tilden          | Tilden Mining Company                        |
| Treasury Grant  | Section 1603 Renewable Energy Treasury Grant |
| VAPP            | Valley Power Plant                           |

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## 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 rate, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, 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 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, as well as the recovery of the related costs through rates;
- The impact of federal, state, and local legislative and 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, and energy efficiency mandates;
- The uncertainty surrounding the recently enacted Tax Legislation, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and its impact, if any, on our or our subsidiaries' credit ratings;
- 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 permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;
- 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;
- Increased pressure on us by investors and other stakeholder groups to take more aggressive action to reduce future 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;

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- Changes in credit ratings, interest rates, and our ability to access the capital markets, caused by volatility in the global credit markets, our capitalization structure, and market perceptions of the utility industry, us, or any of our subsidiaries;
- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;
- 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 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;
- The financial performance of ATC and its corresponding contribution to our earnings, as well as the ability of ATC and DATC to obtain the required approvals for their transmission projects;
- 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 that result in competitive disadvantages and create the potential for impairment of existing assets;
- The timing, costs, and anticipated benefits associated with the remaining integration efforts relating to the Integrys acquisition;
- 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 Section 404 of the Sarbanes-Oxley Act, 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 "us," "we," "our," or "ours," we are referring to WEC Energy Group, Inc. 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 WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, including financial and geographic information about each reportable business segment, see Note 19, 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. Our wholly owned subsidiaries provide regulated natural gas and electricity, as well as nonregulated renewable energy. Another subsidiary, ITF, provided CNG products and services prior to its sale in the first quarter of 2016. See Note 3, Dispositions, for more information on this sale. We have an approximately 60% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2017, we had six reportable segments, which are discussed below. For additional information about our reportable segments, see Note 19, Segment Information.

#### Integrys Acquisition

On June 29, 2015, we acquired 100% of the outstanding common shares of Integrys and changed our name to WEC Energy Group, Inc. For additional information on this acquisition, see Note 2, Acquisitions.

#### Available Information

Our annual and periodic filings with the SEC are available, free of charge, on our website, [www.wecenergygroup.com](http://www.wecenergygroup.com), as soon as reasonably practicable after they are filed with or furnished to the SEC.

You may obtain materials we filed with or furnished to the SEC at the SEC Public Reference Room at 100 F Street, NE, Washington, DC 20549. To obtain information on the operation of the Public Reference Room, you may call the SEC at 1-800-SEC-0330. You may also view information filed or furnished electronically with the SEC at the SEC's website at [www.sec.gov](http://www.sec.gov).

### B. UTILITY ENERGY OPERATIONS

#### Wisconsin Segment

The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, WPS, and UMERC, which includes WE's electric operations and WPS's electric and natural gas operations in the state of Michigan that were transferred to UMERC effective January 1, 2017.

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. See Note 23, Regulatory Environment, for more information. UMERC became operational effective January 1, 2017, and WE and WPS transferred customers and property, plant, and equipment as of that date. WE transferred approximately 27,500 retail electric customers and 50 electric distribution-only customers to UMERC, along with approximately 2,500 miles of electric distribution lines. WPS transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along

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with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. WE and WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of net assets, including the related deferred income tax liabilities, transferred to UMERC from WE and WPS as of January 1, 2017, was \$61.1 million and \$20.6 million, respectively. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

## Electric Utility Operations

For the periods presented in this Annual Report on Form 10-K, our electric utility operations included operations of WE for all periods, operations for WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries, and operations for UMERC beginning January 1, 2017, due to the transfer of customers and assets located in the Upper Peninsula of Michigan from WE and WPS.

- WE, which is the largest electric utility in the state of Wisconsin, generates and distributes electric energy to customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, and northern Wisconsin, and serves an iron ore mine customer, Tilden, in the Upper Peninsula of Michigan.
- WPS generates and distributes electric energy to customers located in northeastern and central Wisconsin.
- UMERC supplies and distributes electric energy to customers located in the Upper Peninsula of Michigan. UMERC currently meets its market obligations through power purchase agreements with WE and WPS. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur in 2019. For more information on UMERC's new generation solution, see the discussion below under the heading "Natural Gas-Fired Generation."

## Operating Revenues

The following table shows electric utility operating revenues, including steam operations, for the past three years:

| <i>(in millions)</i>                           | Year Ended December 31 |                   |                     |
|--|------------------------|-------------------|---------------------|
|  | 2017                   | 2016              | 2015 <sup>(1)</sup> |
| <b>Operating revenues</b>                      |                        |                   |                     |
| Residential                                    | \$ 1,581.5             | \$ 1,620.7        | \$ 1,398.5          |
| Small commercial and industrial <sup>(2)</sup> | 1,400.9                | 1,418.1           | 1,235.7             |
| Large commercial and industrial <sup>(2)</sup> | 913.7                  | 949.5             | 858.8               |
| Other  | 30.5                   | 29.8              | 26.9                |
| <b>Total retail revenues <sup>(2)</sup></b>    | <b>3,926.6</b>         | <b>4,018.1</b>    | <b>3,519.9</b>      |
| Wholesale                                      | 233.4                  | 231.2             | 181.4               |
| Resale   | 270.6                  | 247.1             | 248.7               |
| Steam  | 23.3                   | 27.2              | 41.0                |
| Other operating revenues <sup>(3)</sup>        | 105.1                  | 104.5             | 77.5                |
| <b>Total operating revenues <sup>(2)</sup></b> | <b>\$ 4,559.0</b>      | <b>\$ 4,628.1</b> | <b>\$ 4,068.5</b>   |

(1) Includes the operations of WPS beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015.

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

(3) 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 are being deferred until a future rate proceeding. For more information, see the discussion below under the heading "Large Electric Retail Customers."

**Electric Sales**

Our electric energy deliveries included supply and distribution sales to retail and wholesale customers and distribution sales to those customers who switched to an alternative electric supplier. In 2017, retail electric revenues accounted for 86.1% of total electric operating revenues, while wholesale and resale electric revenues accounted for 11.1% 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 and sell power. For more information, see D. Regulation.

**Steam Sales**

WE has a steam utility that generates, distributes, and sells steam supplied by 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. In April 2016, we sold the MCPP steam generation and distribution assets, located in Wauwatosa, Wisconsin. MCPP primarily provided steam to the Milwaukee Regional Medical Center hospitals and other campus buildings. See Note 3, Dispositions, for more information.

**Electric Sales Forecast**

Our combined service territories in Wisconsin experienced slightly lower weather-normalized retail electric sales in 2017, driven by lower residential use per customer and the late 2016 closure of a major large commercial and industrial customer. These reductions were partially offset by modest growth in the number of residential customers. We currently forecast retail electric sales volumes and the associated peak demand, excluding the Tilden mine located in the Upper Peninsula of Michigan, to be flat or grow very slightly over the next five years, assuming normal weather.

**Customers**

| <i>(in thousands)</i>                         | Year Ended December 31 |                |                |
|---|------------------------|----------------|----------------|
|   | 2017                   | 2016           | 2015           |
| <b>Electric customers – end of year</b>       |                        |                |                |
| Residential                                   | 1,431.4                | 1,421.7        | 1,414.1        |
| Small commercial and industrial               | 172.2                  | 171.1          | 171.1          |
| Large commercial and industrial               | 0.9                    | 0.9            | 1.0            |
| Other   | 3.0                    | 3.0            | 3.1            |
| <b>Total electric customers – end of year</b> | <b>1,607.5</b>         | <b>1,596.7</b> | <b>1,589.3</b> |
| <b>Steam customers – end of year</b>          | <b>0.4</b>             | <b>0.4</b>     | <b>0.4</b>     |

**Large Electric Retail Customers**

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

In February 2015, Tilden, along with another affiliated iron ore mine located in the Upper Peninsula of Michigan, returned as customers after choosing an alternative electric supplier in September 2013. For more information on alternative electric suppliers, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Industry Restructuring. WE entered into a contract with each of the mines to provide full requirements electric service through December 31, 2019. Since 2015, we have been deferring, and expect to continue to defer, the revenue less costs of sales from the mine sales and will apply these amounts for the benefit of Wisconsin retail electric customers in a future rate proceeding.

In 2016, one of the iron ore mines closed, and the related contract for full requirements electric service was terminated. In August 2016, we entered into a new agreement with Tilden under which it will purchase electric power from UMERC for 20 years for the remaining mine, contingent upon UMERC's construction of natural gas-fired generation in the Upper Peninsula of Michigan. Tilden will continue to receive full requirements electric service from WE under the existing contract until UMERC's generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur in 2019. See Note 23, Regulatory Environment, for more information, as well as the discussion under the heading "Natural Gas-Fired Generation" below.

### Wholesale Customers

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. Wholesale sales accounted for 7.6%, 7.4%, and 6.0% of total electric energy sales volumes during 2017, 2016, and 2015, respectively. Wholesale revenues accounted for 5.1%, 5.0%, and 4.5% of total electric operating revenues during 2017, 2016, and 2015, respectively.

### Resale

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. Resale sales accounted for 18.2%, 17.5%, and 20.9% of total electric energy sales volumes during 2017, 2016, and 2015, respectively. Resale revenues accounted for 5.9%, 5.3%, and 6.1% of total electric operating revenues during 2017, 2016, and 2015, respectively. Retail fuel costs are reduced by the amount that revenue exceeds the costs of sales derived from these opportunity sales.

### 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 maintain a stable, reliable, and affordable supply of electricity. 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 capacity into the MISO Energy Markets when it is economical, which reduces net fuel costs by offsetting costs of purchased power.

Our rated capacity by fuel type as of December 31 is shown below. For more information on our electric generation facilities, see Item 2. Properties.

|  | Rated Capacity in MW <sup>(1)</sup> |              |              |
|--|-------------------------------------|--------------|--------------|
|  | 2017                                | 2016         | 2015         |
| Coal   | 4,935                               | 4,933        | 4,955        |
| Natural gas:                                 |                                     |              |              |
| Combined cycle                               | 1,753                               | 1,697        | 1,636        |
| Steam turbine <sup>(2)</sup>                 | 314                                 | 320          | 305          |
| Natural gas/oil peaking units <sup>(3)</sup> | 1,458                               | 1,413        | 1,412        |
| Renewables <sup>(4)</sup>                    | 273                                 | 273          | 269          |
| <b>Total rated capacity</b>                  | <b>8,733</b>                        | <b>8,636</b> | <b>8,577</b> |

(1) Rated capacity 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. We have summer peaking electric utilities, and amounts are based on expected capacity ratings for the following summer. The values were established by tests and may change slightly from year to year.

(2) The natural gas steam turbine represents the rated capacity associated with VAPP as well as Weston Unit 2.

(3) The dual-fueled facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local natural gas distribution company that delivers natural gas to the plants.

(4) Includes hydroelectric, biomass, and wind generation.

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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 2018:

|   | Estimate      | Actual        |        |        |
|---|---------------|---------------|--------|--------|
|   | 2018          | 2017          | 2016   | 2015   |
| <b>Company-owned generation units:</b>      |               |               |        |        |
| Coal  | 46.1%         | <b>48.5%</b>  | 45.7%  | 51.5%  |
| <b>Natural gas:</b>                         |               |               |        |        |
| Combined cycle                              | 20.0%         | <b>16.5%</b>  | 18.2%  | 14.6%  |
| Steam turbine                               | 0.5%          | <b>0.8%</b>   | 0.9%   | 1.2%   |
| Natural gas/oil peaking units               | 0.8%          | <b>1.1%</b>   | 1.1%   | 0.6%   |
| Renewables                                  | 3.9%          | <b>4.1%</b>   | 3.9%   | 3.4%   |
| <b>Total company-owned generation units</b> | <b>71.3%</b>  | <b>71.0%</b>  | 69.8%  | 71.3%  |
| <b>Power purchase contracts:</b>            |               |               |        |        |
| Nuclear                                     | 17.9%         | <b>17.7%</b>  | 17.5%  | 20.5%  |
| Natural gas                                 | 2.1%          | <b>1.3%</b>   | 1.7%   | 1.4%   |
| Renewables                                  | 2.9%          | <b>2.9%</b>   | 2.8%   | 1.5%   |
| Other                                       | 1.7%          | <b>1.6%</b>   | 2.1%   | 3.5%   |
| <b>Total power purchase contracts</b>       | <b>24.6%</b>  | <b>23.5%</b>  | 24.1%  | 26.9%  |
| Purchased power from MISO                   | 4.1%          | <b>5.5%</b>   | 6.1%   | 1.8%   |
| <b>Total purchased power</b>                | <b>28.7%</b>  | <b>29.0%</b>  | 30.2%  | 28.7%  |
| <b>Total electric utility supply</b>        | <b>100.0%</b> | <b>100.0%</b> | 100.0% | 100.0% |

**Coal-Fired Generation**

Our coal-fired generation consists of eight operating plants with a rated capacity of 4,935 MW as of December 31, 2017. For more information about our operating plants, see Item 2. Properties. As a result of our generation reshaping plan, we expect to retire approximately 1,800 MW of coal generation by 2020 with a goal of reducing CO<sub>2</sub> emissions by approximately 40% below 2005 levels by 2030. For more information about future retirement of our plants, see Note 5, Property, Plant, and Equipment.

**Natural Gas-Fired Generation**

Our natural gas-fired generation currently consists of nine operating plants, including peaking units, with a rated capacity of 3,325 MW as of December 31, 2017. For more information about our operating plants, see Item 2. Properties.

In October 2017, the MPSC approved UMERG's application for a certificate of necessity to begin construction of a long-term generation solution for electric reliability in the region. UMERG will construct and operate approximately 180 MW of natural gas-fired generation located in the Upper Peninsula of Michigan. The new generation is expected to achieve commercial operation in 2019. See Note 23, Regulatory Environment, for more information.

**Oil-Fired Generation**

Fuel oil is used for combustion turbines at certain of our natural gas-fired plants as well as for ignition and flame stabilization at one of our coal-fired plants. Our oil-fired generation had a rated capacity of 200 MW as of December 31, 2017. We also have natural gas-fired peaking units with a rated capacity of 1,239 MW, which have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our operating plants, see Item 2. Properties.

**Renewable Generation**

Our electric utilities meet a portion of their electric generation supply with various renewable energy resources. This helps our electric utilities maintain compliance with renewable energy legislation in Wisconsin and Michigan. 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. For more information about our renewable generation, see Item 2. Properties.

## **Hydroelectric**

Our hydroelectric generating system consists of 30 operating plants with a total installed capacity of 173 MW and a rated capacity of 151 MW as of December 31, 2017. All of our hydroelectric facilities follow FERC guidelines and/or regulations.

## **Wind**

We have six wind sites, consisting of 280 turbines, with an installed capacity of 447 MW and a rated capacity of 72 MW as of December 31, 2017. In October 2017, WPS, along with two other non-affiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. WPS currently purchases 44.6% of the facility's energy output under a power purchase agreement, which is approximately 58 MW. The FERC approved the transaction in January 2018. The transaction remains subject to PSCW approval and is expected to close in the spring of 2018. See Note 2, Acquisitions, for more information.

## **Biomass**

We have a biomass-fueled power plant at a Rothschild, Wisconsin paper mill site. Wood waste and wood shavings are used to produce a rated capacity of approximately 50 MW of 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.

## ***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 15.8% installed capacity reserve margin requirement for the planning year from June 1, 2017, through May 31, 2018, and a 17.1% installed capacity reserve margin requirement for the planning year from June 1, 2018, through May 31, 2019. MISO's short-term reserve margin requirements experience year-to-year fluctuations, primarily due to changes in the average forced outage rate of generation within the MISO footprint.

Michigan recently passed legislation requiring 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, 2018, through May 31, 2019. 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 and first upcoming planning years. We also fully anticipate that we will have adequate capacity to meet the planning reserve margin requirements for future planning years in both jurisdictions. However, extremely hot weather, unexpected equipment failure, or unavailability across the 15-state MISO footprint could require us to call upon load management procedures. Load management procedures allow for the reduction of energy use through agreements with customers to directly shut off their equipment or through interruptible service, where customers agree to reduce their load in the case of an emergency interruption.

## ***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 D. Regulation.

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

|                               | 2017     | 2016     | 2015     |
|-------------------------------|----------|----------|----------|
| Coal                          | \$ 23.05 | \$ 23.09 | \$ 25.57 |
| Natural gas combined cycle    | 22.65    | 18.79    | 17.66    |
| Natural gas/oil peaking units | 53.91    | 45.08    | 56.99    |
| Biomass                       | 118.76   | 103.24   | 168.84   |
| Purchased power               | 42.12    | 40.11    | 43.50    |

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. To moderate the volatility, WE and WPS were both given PSCW approval for a hedging program, which allows them to hedge up to 75% of their potential risks related to rail transportation fuel surcharge exposure. However, due to decreased volatility over the last two years, we suspended the fuel surcharge hedging program in 2017.

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-approved programs that allow them to hedge up to 75% of their estimated natural gas use for electric generation in order to help manage their natural gas price risk.

Our hedging programs are generally implemented on a 36-month forward-looking basis. The results of these programs are reflected in the average costs of natural gas and purchased power.

### Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming, as well as from various other states. For 2018, approximately 83% of our total projected coal requirements of 10.8 million tons are contracted under fixed-price contracts. See Note 21, 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:

| <i>(in thousands)</i> | Annual Tonnage |
|-----------------------|----------------|
| 2018                  | 8,932          |
| 2019                  | 5,528          |
| 2020                  | 2,573          |

### Coal Deliveries

All of our 2018 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, Pennsylvania, and Montana. The coal is transported by train to our rail-served electric-generating facilities and to dock storage in Superior, Wisconsin, until needed by our lake vessel-served facility. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities.

### Midcontinent Independent System Operator Costs

In connection with its status as a FERC approved RTO, MISO developed and operates the MISO Energy Markets, which include its bid-based energy market and ancillary services market. We are participants in the MISO Energy Markets. For more information on MISO, see D. Regulation.

### 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 1,445 MW for 2018 and 1,387 MW per year for years 2019 through 2022, 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. Due to the planned retirement of generation resources, we have entered into purchase agreements to procure additional planning capacity in order to maintain our compliance with planning reserve requirements as established by the PSCW, MPSC, and MISO.

## **Other Matters**

### **Seasonality**

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, WE did not require public appeals for conservation, and it did not interrupt or curtail service to non-firm customers who participate in load management programs. In addition, WPS did not require any public appeals for conservation, and it did not interrupt or curtail service to non-firm customers who participate in load management programs for capacity reasons. However, WPS did have service curtailments for economic interruptions. Economic interruptions are declared during times in which the price of electricity in the regional market significantly exceeds the cost of operating the company's peaking generation. During this time, interruptible customers can choose to continue using electricity at a price that exceeds the tariff rate.

### **Competition**

Our electric utilities face competition from various entities and other forms of energy sources available to customers, including self-generation by large industrial 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.

For more information on competition in 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 – Industry Restructuring.

### **Environmental Matters**

For information regarding environmental matters, especially as they relate to coal-fired generating facilities, see Note 21, Commitments and Contingencies.

### **Natural Gas Utility Operations**

For the periods presented in this Annual Report on Form 10-K, our Wisconsin natural gas utility operations include WG's and WE's natural gas operations for all periods and WPS's natural gas operations, including in the Upper Peninsula of Michigan, beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries. Effective January 1, 2017, WPS transferred its natural gas customers and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC, which is included in our Wisconsin segment. More information about UMERC is included at the beginning of the Wisconsin segment section.

We 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. We also transport customer-owned natural gas. Together our natural gas distribution utilities are the largest in Wisconsin, and we operate throughout the state, including the City of Milwaukee and surrounding areas, northeastern Wisconsin, and in large areas of both central and western Wisconsin.

## Natural Gas Utility Operating Statistics

The following table shows certain natural gas utility operating statistics at our Wisconsin segment for the past three years:

|   | Year Ended December 31 |                   |                     |
|---|------------------------|-------------------|---------------------|
|   | 2017                   | 2016              | 2015 <sup>(1)</sup> |
| <b>Operating revenues (in millions)</b>       |                        |                   |                     |
| Residential                                   | \$ 809.3               | \$ 763.2          | \$ 696.2            |
| Commercial and industrial                     | 395.5                  | 355.3             | 332.8               |
| <b>Total retail revenues</b>                  | <b>1,204.8</b>         | <b>1,118.5</b>    | <b>1,029.0</b>      |
| Transport                                     | 72.6                   | 69.7              | 62.8                |
| Other operating revenues <sup>(2)</sup>       | (7.2)                  | (10.6)            | 30.8                |
| <b>Total</b>                                  | <b>\$ 1,270.2</b>      | <b>\$ 1,177.6</b> | <b>\$ 1,122.6</b>   |
| <b>Customers – end of year (in thousands)</b> |                        |                   |                     |
| Residential                                   | 1,322.9                | 1,311.0           | 1,299.7             |
| Commercial and industrial                     | 125.1                  | 124.3             | 123.4               |
| Transport                                     | 2.8                    | 2.6               | 2.6                 |
| <b>Total customers</b>                        | <b>1,450.8</b>         | <b>1,437.9</b>    | <b>1,425.7</b>      |

(1) Includes the operations of WPS beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015.

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

### Natural Gas Deliveries

Our gas therm deliveries include customer-owned transported natural gas. Transported natural gas accounted for approximately 43.9% of the total volumes delivered during each of 2017 and 2016, and 41.8% during 2015. Our peak daily send-out during 2017 was 23.9 million therms on December 27, 2017.

### Large Natural Gas Customers

We provide natural gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include governmental, paper, education, health services, and restaurants.

### Natural Gas Sales Forecast

Our combined service territories in Wisconsin experienced growth in weather-normalized natural gas deliveries (excluding natural gas deliveries for electric generation) in 2017 due to positive customer growth, an improving economy, and favorable natural gas prices. We currently forecast retail natural gas delivery volumes to grow at a rate between flat and 0.5% over the next five years, assuming normal weather. The forecast projects declining average usage per customer partially offsetting positive customer growth.

### 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 21, 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 the daily and seasonal 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 winter demand; November through March is considered the winter season. Storage capacity, along with our natural gas purchase contracts, enables

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us to manage significant changes in daily 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 when demand is lower and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity during periods of peak usage than would otherwise be necessary and can purchase natural gas on a more uniform daily basis from suppliers year-round. Each of these capabilities enables us to reduce our overall costs.

We hold daily transportation and storage capacity entitlements with interstate pipeline companies as well as other service providers under varied-length long-term contracts.

To ensure a reliable supply of natural gas during peak winter conditions, we have liquefied natural gas 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 June 2017, we completed the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that will 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.

### **Term Natural Gas Supply**

We have contracts for firm supplies with terms of 3–5 months 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.

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 natural gas utilities' forecasted design peak-day throughput is 32.0 million therms for the 2017 through 2018 heating season.

### **Secondary Market Transactions**

Pipeline and storage capacity and natural gas supplies under contract can be resold in secondary markets. As local distribution companies, our Wisconsin natural gas utilities must contract for capacity and supply sufficient to meet the firm peak-day demand of their customers. Peak or near-peak demand days generally occur only a few times each year. The secondary markets facilitate higher utilization of contracted capacity and supply during those times when the full contracted capacity and supply are not needed by the utility, helping to mitigate the fixed costs associated with maintaining peak levels of capacity and natural gas supply. Through pre-arranged agreements and day-to-day electronic bulletin board postings, interested parties can purchase this excess capacity and supply. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. During 2017, we continued to participate in the secondary markets. For information on the GCRMs, see Note 1(d), Revenues and Customer Receivables.

### **Spot Market Natural Gas Supply**

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 and brokerage fees) and proceeds (gains and losses) to customers through their respective GCRMs. Hedge targets (volumes) are provided annually to the PSCW as part of each company's three-year natural gas supply plan and risk management filing.

To the extent that opportunities develop and physical supply operating plans are supportive, WE, WG, and WPS 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.

### **Seasonality**

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.

Our 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**

Competition in varying degrees exists between natural gas and other forms of energy available to consumers. A number of our large commercial and industrial customers are dual-fuel customers that are equipped to switch between natural gas and alternative fuels. We are allowed to offer lower-priced natural gas sales and transportation services to dual-fuel customers. Under natural gas transportation agreements, customers purchase natural gas directly from natural gas marketers and arrange with interstate pipelines and us to have the natural gas transported to their facilities. We earn substantially the same operating income whether we sell and transport natural gas to customers or only transport their natural gas.

Our ability to maintain our share of the industrial dual-fuel market depends on our success and the success of third-party natural gas marketers in obtaining long-term and short-term supplies of natural gas at competitive prices compared to other sources and in arranging or facilitating competitively priced transportation service for those customers that desire to buy their own natural gas supplies.

Federal and state regulators continue to implement policies to bring more competition to the natural gas industry. While the natural gas utility distribution function is expected to remain a highly regulated, monopoly function, the sale of the natural gas commodity and related services are expected to remain subject to competition from third parties for large commercial and industrial customers.

### **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. We acquired PGL and NSG as a result of the acquisition of Integrys on June 29, 2015. Our customers are located in Chicago and the northern suburbs of Chicago.

## Illinois Utilities Operating Statistics

The following table shows certain Illinois utility operating statistics since the acquisition of Integrys.

|   | Year Ended December 31 |                   |                 |
|---|------------------------|-------------------|-----------------|
|   | 2017                   | 2016              | 2015 *          |
| <b>Operating revenues (in millions)</b>       |                        |                   |                 |
| Residential                                   | \$ 934.8               | \$ 839.2          | \$ 309.8        |
| Commercial and industrial                     | 156.7                  | 136.5             | 50.4            |
| <b>Total retail revenues</b>                  | <b>1,091.5</b>         | <b>975.7</b>      | <b>360.2</b>    |
| Transport                                     | 246.9                  | 239.4             | 97.1            |
| Other operating revenues                      | 17.1                   | 27.1              | 46.1            |
| <b>Total</b>                                  | <b>\$ 1,355.5</b>      | <b>\$ 1,242.2</b> | <b>\$ 503.4</b> |
| <b>Customers – end of year (in thousands)</b> |                        |                   |                 |
| Residential                                   | 854.3                  | 846.8             | 838.2           |
| Commercial and industrial                     | 47.8                   | 47.1              | 46.2            |
| Transport                                     | 103.9                  | 109.5             | 107.8           |
| <b>Total customers</b>                        | <b>1,006.0</b>         | <b>1,003.4</b>    | <b>992.2</b>    |

\* Includes the operations of PGL and NSG beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015.

## 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.

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.

For more information on our natural gas utility supply and transportation contracts, see Note 21, Commitments and Contingencies.

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. 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. They hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

We own a 38.3 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 eight 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.

We had adequate capacity to meet all firm natural gas demand obligations during 2017 and expect to have adequate capacity to meet all firm demand obligations during 2018. Our Illinois utilities' forecasted design peak-day throughput is 24.5 million therms for the 2017 through 2018 heating season.

## **Gas System Modernization Program**

PGL is continuing work on the SMP, a project that began in 2011 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. For information on regulatory proceedings related to the SMP, see Note 23, Regulatory Environment.

## **Seasonality**

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 variations in earnings and working capital throughout the year as a result of changes in weather.

Our Illinois 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**

Although our Illinois utilities' rates are regulated by the ICC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. Absent extraordinary circumstances, potential competitors are not allowed to construct competing natural gas distribution systems in our service territory due to a judicial doctrine known as the "first in the field." In addition, we believe it would be impractical to construct competing duplicate distribution facilities due to the high cost of installation.

Since 2002, all our Illinois utilities' natural gas customers have had the opportunity to choose a natural gas supplier other than us. As a result, we offer natural gas transportation service to enable customers to directly manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution system to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. 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.

An interstate pipeline may seek to provide transportation service directly to end users, which would bypass our natural gas transportation service. However, we have a bypass rate approved by the ICC, which allows us to negotiate rates with customers that are potential bypass candidates to help ensure that such customers use our transportation service.

## **Other States Segment**

Our other states segment includes the natural gas utility operations of MERC and MGU. We acquired the natural gas distribution operations of MERC and MGU, located in Minnesota and Michigan, respectively, on June 29, 2015, with the acquisition of Integrys. MERC serves customers in various cities and communities throughout Minnesota, and MGU serves customers in southern and western Michigan.

## Other States Utilities Operating Statistics

The following table shows certain other states utility operating statistics since the acquisition of Integrys.

|   | Year Ended December 31 |                 |                 |
|---|------------------------|-----------------|-----------------|
|   | 2017                   | 2016            | 2015 *          |
| <b>Operating revenues (in millions)</b>       |                        |                 |                 |
| Residential                                   | \$ 220.2               | \$ 209.3        | \$ 67.6         |
| Commercial and industrial                     | 123.9                  | 110.7           | 38.8            |
| <b>Total retail revenues</b>                  | <b>344.1</b>           | <b>320.0</b>    | <b>106.4</b>    |
| Transport                                     | 31.4                   | 31.7            | 11.5            |
| Other operating revenues                      | 35.7                   | 24.8            | 31.4            |
| <b>Total</b>                                  | <b>\$ 411.2</b>        | <b>\$ 376.5</b> | <b>\$ 149.3</b> |
| <b>Customers – end of year (in thousands)</b> |                        |                 |                 |
| Residential                                   | 353.0                  | 348.1           | 345.8           |
| Commercial and industrial                     | 34.5                   | 34.1            | 33.8            |
| Transport                                     | 24.2                   | 24.8            | 23.0            |
| <b>Total customers</b>                        | <b>411.7</b>           | <b>407.0</b>    | <b>402.6</b>    |

\* Includes the operations of MERC and MGU beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015.

## 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.

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.

For more information on our natural gas utility supply and transportation contracts, see Note 21, Commitments and Contingencies.

We own a storage field (Partello in Michigan) 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 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 other states utilities when negotiating new agreements for transportation and storage services. 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 hedges up to 30% of planned winter demand using NYMEX financial instruments. MGU hedges up to 20% of its planned annual purchases using NYMEX financial instruments.

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 segment is 8.6 million therms for the 2017 through 2018 heating season.

## Seasonality

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 variations in earnings and working capital throughout the year as a result of changes in weather.

Our other states 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

Although our other states utilities' rates are regulated by the MPUC and MPSC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. 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 utility to utility competition for customers.

Many large commercial and industrial customers have the ability to switch between natural gas and alternative fuels. In addition, MERC commercial and industrial customers and all MGU customers have the opportunity to choose a natural gas supplier other than us. We offer natural gas transportation service and also offer interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution systems to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. 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. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

## 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 UMER, 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 and WPS are non-transmission owning members and customers of MISO. As of December 31, 2017, our ownership interest in ATC was approximately 60%. In addition, we 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. As of December 31, 2017, we had an investment of \$37.6 million in ATC Holdco.

In April 2011, ATC and Duke Energy announced the creation of a joint venture, DATC, that seeks opportunities to acquire, build, own, and operate new electric transmission infrastructure in North America to address increasing demand for affordable, reliable transmission capacity. In April 2013, DATC acquired a 72% interest in California's Path 15 transmission rights. DATC continues to evaluate new projects and opportunities, along with participating in the competitive bidding process on projects it considers viable. These projects are located in the service territories of several different RTOs around the country. See Note 18, Investment in Transmission Affiliates, for more information.

ATC is currently named as one of several parties to a complaint filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners. 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.

## C. NON-UTILITY OPERATIONS

### Non-Utility Energy Infrastructure Segment

The non-utility energy infrastructure segment includes the operations of We Power and of Bluewater following its acquisition in June 2017. See Note 2, Acquisitions, for more information on Bluewater.

We Power, through wholly owned subsidiaries, designed and built approximately 2,450 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

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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, the MPSC, 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, located in southeast Michigan, provides natural gas storage and hub services to WE, WG, and WPS. This gas storage can provide approximately one-third of the current storage needs for the WE, WG, and WPS natural gas distribution service customers. WE, WG, and WPS have entered into long-term service agreements for natural gas storage with Bluewater.

### **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, Wisvest (prior to the sale of its assets in the first quarter of 2016), WECC, WBS, PDL, and ITF (prior to the sale of this business in the first quarter of 2016). See Note 3, Dispositions, for more information on the sale of Wisvest's assets and ITF.

Wispark develops and invests in real estate. Wispark had \$45.9 million in real estate holdings at December 31, 2017. Wispark has developed several business parks and other commercial real estate projects, primarily in southeastern Wisconsin.

Bostco was originally formed to develop and invest in real estate. In March 2017, we sold the remaining real estate holdings of Bostco located in downtown Milwaukee, Wisconsin, which included retail, office, and residential space. See Note 3, Dispositions, for more information. Bostco no longer has significant operations.

Wisvest was originally formed to develop, own, and operate electric generating facilities and to invest in other energy-related entities. However, Wisvest discontinued its development activity several years ago. In April 2016, we sold the chilled water generation and distribution assets of Wisvest, which provided chilled water services to the Milwaukee Regional Medical Center. Wisvest no longer has significant operations.

WECC was originally formed to invest in non-utility projects, such as low income housing developments. However, due to a focus on our regulated utility business, WECC sold many of its non-utility investments and no longer has significant operations.

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. During 2016, PDL sold its natural gas-fired cogeneration facility and its landfill gas facility. These facilities were not significant to our operations. PDL's solar facilities rely on solar irradiance, a renewable energy resource. There is no market price risk associated with the fuel supply of these solar projects. However, production at these facilities can be intermittent due to the variability of solar irradiance.

## D. REGULATION

We are a holding company and are subject to the requirements of the Public Utility Holding Company Act of 2005 (PUHCA 2005). We also have various subsidiaries that meet the definition of a holding company under 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, from being counted against the asset cap provided that they are employed in qualifying businesses. We report to the PSCW annually 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 also subject to regulations, where applicable, of the EPA, the WDNR, the MDEQ, the Michigan Department of Natural Resources, the Illinois Environmental Protection Agency, 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 2017. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

| Regulated Rates                         | Regulatory Commission |
|---|-----------------------|
| <b>WE</b>                               |                       |
| Retail electric, natural gas, and steam | PSCW                  |
| Retail electric                         | MPSC                  |
| Wholesale power                         | FERC                  |
| <b>WPS</b>                              |                       |
| Retail electric and natural gas         | PSCW                  |
| Wholesale power                         | FERC                  |
| <b>WG</b>                               |                       |
| Retail natural gas                      | PSCW                  |
| <b>UMERC</b>                            |                       |
| Retail electric and natural gas         | MPSC                  |
| Wholesale power                         | FERC                  |
| <b>PGL</b>                              |                       |
| Retail natural gas                      | ICC                   |
| <b>NSG</b>                              |                       |
| Retail natural gas                      | ICC                   |
| <b>MERC</b>                             |                       |
| Retail natural gas                      | MPUC                  |
| <b>MGU</b>                              |                       |
| Retail natural gas                      | MPSC                  |

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.

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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.

For a summary of the significant mechanisms our utility subsidiaries had in place in 2017 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts, see Note 1(d), Revenues and Customer Receivables.

In May 2015, the PSCW approved the acquisition of Integrys on the condition that WE and WG each be subject to an earnings sharing mechanism for three years beginning January 1, 2016. See Note 2, Acquisitions, for more information on these earnings sharing mechanisms.

For information on how rates are set for our regulated entities, see Note 23, Regulatory Environment. Orders from our respective regulators can be viewed at the following websites:

| Regulatory Commission | Website   |
|-----------------------|---|
| PSCW                  | <a href="https://psc.wi.gov/">https://psc.wi.gov/</a>                     |
| ICC                   | <a href="https://www.icc.illinois.gov/">https://www.icc.illinois.gov/</a> |
| MPSC                  | <a href="http://www.michigan.gov/mpsc/">http://www.michigan.gov/mpsc/</a> |
| MPUC                  | <a href="http://mn.gov/puc/">http://mn.gov/puc/</a>                       |
| FERC                  | <a href="http://www.ferc.gov/">http://www.ferc.gov/</a>                   |

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:

| <i>(in millions)</i>                      | 2017              |               | 2016              |               | 2015              |               |
|---|-------------------|---------------|-------------------|---------------|-------------------|---------------|
|   | Amount            | Percent       | Amount            | Percent       | Amount            | Percent       |
| <b>Electric *</b>                         |                   |               |                   |               |                   |               |
| Wisconsin                                 | \$ 3,909.1        | 85.7%         | \$ 3,974.8        | 85.9%         | \$ 3,466.3        | 85.2%         |
| Michigan                                  | 145.9             | 3.2%          | 175.0             | 3.8%          | 173.1             | 4.3%          |
| FERC – Wholesale                          | 504.0             | 11.1%         | 478.3             | 10.3%         | 429.1             | 10.5%         |
| <b>Total</b>                              | <b>4,559.0</b>    | <b>100.0%</b> | <b>4,628.1</b>    | <b>100.0%</b> | <b>4,068.5</b>    | <b>100.0%</b> |
| <b>Natural Gas *</b>                      |                   |               |                   |               |                   |               |
| Wisconsin                                 | 1,266.4           | 41.7%         | 1,174.2           | 42.0%         | 1,121.3           | 63.2%         |
| Illinois                                  | 1,355.5           | 44.6%         | 1,242.2           | 44.4%         | 503.4             | 28.4%         |
| Minnesota                                 | 272.6             | 9.0%          | 249.4             | 8.9%          | 98.3              | 5.5%          |
| Michigan                                  | 142.4             | 4.7%          | 130.5             | 4.7%          | 52.3              | 2.9%          |
| <b>Total</b>                              | <b>3,036.9</b>    | <b>100.0%</b> | <b>2,796.3</b>    | <b>100.0%</b> | <b>1,775.3</b>    | <b>100.0%</b> |
| <b>Total utility operating revenues *</b> | <b>\$ 7,595.9</b> |               | <b>\$ 7,424.4</b> |               | <b>\$ 5,843.8</b> |               |

\* Includes the operations of WPS, PGL, NSG, MERC, and MGU beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015.

**Electric Transmission, Capacity, and Energy Markets**

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO enhanced the energy market by including an ancillary services market. In the MISO ancillary services market, we buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market has been able to reduce overall ancillary services costs in the MISO footprint, and has enabled MISO 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.

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As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented 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, 2017, through May 31, 2018. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has instituted 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. Our capacity requirements during the 2017 planning year were fulfilled using our own capacity resources.

### **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 WE and UMERG are 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 Code of Federal Regulations (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.

## E. ENVIRONMENTAL COMPLIANCE

Our operations 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 of GHG emissions, coal combustion products, air emissions, or wastewater discharges, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and 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 matters related to manufactured gas plant sites and air and water quality, see Note 21, Commitments and Contingencies.

## F. EMPLOYEES

As of December 31, 2017, we had the following number of employees:

|                        | <b>Total Employees</b> |
|------------------------|------------------------|
| WE                     | 2,945                  |
| WPS                    | 1,224                  |
| WG                     | 420                    |
| PGL                    | 1,510                  |
| NSG                    | 163                    |
| MERC                   | 224                    |
| MGU                    | 159                    |
| WBS                    | 1,484                  |
| <b>Total employees</b> | <b>8,129</b>           |

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As of December 31, 2017, we had employees represented under labor agreements with the following bargaining units:

|  | Number of Employees | Expiration Date of Current Labor Agreement |
|--|---------------------|--|
| <b>WE</b>  |                     |  |
| Local 2150 of International Brotherhood of Electrical Workers, AFL-CIO | 1,627               | August 15, 2020                            |
| Local 420 of International Union of Operating Engineers, AFL-CIO       | 443                 | September 30, 2021                         |
| Local 2006 Unit 1 of United Steel Workers of America, AFL-CIO          | 124                 | October 31, 2021                           |
| Local 510 of International Brotherhood of Electrical Workers, AFL-CIO  | 89                  | October 31, 2020                           |
| <b>Total WE</b>  | <b>2,283</b>        |  |
| <b>WPS</b>   |                     |  |
| Local 420 of International Union of Operating Engineers, AFL-CIO       | 881                 | April 16, 2021                             |
| <b>WG</b>  |                     |  |
| Local 2150 of International Brotherhood of Electrical Workers, AFL-CIO | 86                  | August 15, 2020                            |
| Local 2006 Unit 1 of United Steel Workers of America, AFL-CIO          | 214                 | October 31, 2021                           |
| <b>Total WG</b>  | <b>300</b>          |  |
| <b>PGL</b>   |                     |  |
| Local 18007 of Utility Workers Union of America, AFL-CIO (1)           | 934                 | April 30, 2018                             |
| Local 18007(C) of Utility Workers Union of America, AFL-CIO            | 91                  | July 31, 2018                              |
| <b>Total PGL</b>   | <b>1,025</b>        |  |
| <b>NSG</b>   |                     |  |
| Local 2285 of International Brotherhood of Electrical Workers, AFL-CIO | 119                 | June 30, 2019                              |
| <b>MERC (2)</b>  |                     |  |
| Local 31 of International Brotherhood of Electrical Workers, AFL-CIO   | 44                  | May 31, 2020                               |
| <b>MGU</b>   |                     |  |
| Local 12295 of United Steelworkers of America, AFL-CIO-CLC             | 77                  | January 15, 2020                           |
| Local 417 of Utility Workers Union of America, AFL-CIO                 | 29                  | February 15, 2019                          |
| <b>Total MGU</b>   | <b>106</b>          |  |
| <b>Total represented employees</b>                                     | <b>4,758</b>        |  |

(1) In January 2018, PGL and the Gas Workers Union Executive Committee of Local 18007 negotiated a five year agreement to be effective May 1, 2018.

(2) In January 2018, the International Union of Operating Engineers, Local 49, was certified and includes three employees. MERC is in the process of preparing for negotiations.

## 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.***

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 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 and the ability to recover such costs; decommissioning generating facilities and the ability to recover the related costs and continuing to recover the return on the carrying 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 on 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 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 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 CO<sub>2</sub>, methane, mercury, SO<sub>2</sub>, and NO<sub>x</sub>), 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 NO<sub>x</sub>, SO<sub>2</sub>, fine particulate matter, mercury, and other air pollutants under the CAA through the NAAQS, the Mercury and Air Toxics Standards rule, the CPP, the CSAPR, 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. The EPA and the United States Army Corps of Engineers (Army Corps) have also adopted a final rule that would expand traditional federal jurisdiction over navigable waters and related wetlands for permitting and other regulatory matters; however, this rule has been stayed, and the EPA and the Army Corps have proposed rescinding it. 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 new Federal Executive Administration taking office in January 2017 and the actions it has taken to date, as well as other factors, 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, certain of our coal-fired electric generating facilities may become uneconomical to maintain and operate, which could result in some of these units being retired or converted to an alternative type of fuel. For example, we expect to retire approximately 1,800 MW of coal generation by 2020, including Pleasant Prairie power plant, PIPP, Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit. 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 by or that may be recovered from insurance or other third parties. Due to the potential for 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 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, 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 increased generally throughout the United States. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by environmental impacts and alleged exposure to hazardous materials have become more frequent. 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.***

Federal, state, regional, and international authorities have undertaken efforts to limit GHG emissions. In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the CPP, a proposed federal plan and model trading rules

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as alternatives or guides to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. With the January 2017 change in the Federal Executive Administration, the legal and regulatory future of federal GHG regulations, including the CPP, faces increased uncertainty. 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 CPP, any successor rule, and federal GHG regulations in general.

In October 2015, numerous states (including Wisconsin and Michigan) and other parties, filed lawsuits challenging the final rule, including a request to stay the implementation of the final rule pending the outcome of these legal challenges. The D.C. Circuit Court of Appeals denied the stay request, but in February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that further appellate review is sought, at the Supreme Court. The D.C. Circuit Court of Appeals heard one case in September 2016, and the other case is still pending. In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the cases to be held in abeyance. Supplemental briefs were provided addressing whether the cases should be remanded to the EPA rather than held in abeyance. The EPA argued that the cases should continue to be held in abeyance pending the conclusion of the EPA's review of the CPP and any resulting rulemaking.

In March 2017, President Trump issued an executive order that, among other things, specifically directs the EPA to review, and if appropriate, initiate proceedings to suspend, revise, or rescind the CPP and related GHG regulations for new, reconstructed, or modified fossil-fueled power plants. As a result of this order and related EPA review, as well as the ongoing legal proceedings, the timelines for the GHG emission reduction goals and all other aspects of the CPP are uncertain. In April 2017, the EPA withdrew the proposed rule for a federal plan and model trading rules that were published in October 2015 for use in developing state plans to implement the CPP or for use in states where a plan is not submitted or approved. In October 2017, the EPA issued a proposed rulemaking to repeal the CPP. In December 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it is appropriate to replace the CPP. In addition, the Governor of Wisconsin issued an executive order in February 2016, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan to implement the CPP.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with the CPP or other federal regulations or that cost recovery will not be delayed or otherwise conditioned. The CPP and any other related 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. In December 2016, Michigan enacted Act 342, which retains the 10% renewable energy portfolio requirement for years 2016 through 2018, increases the requirement to 12.5% for years 2019 through 2020, and increases the requirement to 15.0% for 2021. These regulations, as well as changes in the fuel markets and advances in technology, could make some of our 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<sub>2</sub> 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, 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 efforts by investors and other stakeholders to increase pressure on us and others to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius. 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.

### ***Recent 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.***

Recently enacted United States federal income 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. The Tax Legislation is unclear in certain respects and will require interpretations and implementing regulations by the Treasury Department and the IRS, as well as state income tax authorities, and the Tax Legislation could be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the Tax Legislation. In addition, the regulatory treatment of the impacts of the Tax Legislation will be subject to the discretion of the FERC and state public utility commissions. State and local taxing authorities are in the early stages

of evaluating the impact of federal income tax reform, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

Although it is unclear when or how capital markets, credit rating agencies, the FERC, or state public utility commissions may ultimately respond to the Tax Legislation, we do expect that certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted as a result of certain limitations on tax deductions and an anticipated decrease in required income tax reimbursement payments to us from our utility subsidiaries. It is uncertain how credit rating agencies will treat the impacts of the Tax Legislation on their credit ratings and metrics, and whether additional opportunities will evolve for companies to manage the adverse aspects of the Tax Legislation, including the impacts on certain credit metrics.

In addition, the FERC and state public utility commissions have started to engage with our utility subsidiaries to determine how any tax savings will be returned to customers. We expect that our utility subsidiaries will return the tax benefits to their customers through refunds, bill credits, riders, or reductions in regulatory assets. The amount of tax benefits to be returned to customers will ultimately be determined by our regulators. If the amounts our regulators order our utility subsidiaries to return to customers exceeds the actual amount of tax savings realized, or our regulators require the tax savings to be applied in a manner other than we had expected, it could have a material adverse effect on our financial condition, results of operations, and cash flow.

While our analysis and interpretation of the Tax Legislation is preliminary and ongoing, based on our current evaluation, 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 downgrading 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.

***Failure to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could have a material effect on our results of operations and stock price.***

We are subject to reporting, disclosure control, and other obligations under Section 404 of the Sarbanes-Oxley Act (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, or will undertake, a variety of initiatives to integrate, standardize, centralize, and streamline our operations with technology, including, but not limited to, an enterprise resource planning system and a customer information and billing system. 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 Wisconsin Utility Holding Company Act (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 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.

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 job losses, decreases in income, and business closings. 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 or disruption of financial markets could adversely affect the financial condition of our customers and demand for their products. 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 associated with cooling and heating. 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 and ability to meet their own energy needs.* 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. 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; 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. To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

***Advances in technology could make our electric generating facilities less competitive.***

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, and energy efficiency. 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. 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.

***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 face on-going threats to our assets and technology systems. Despite the implementation of strong security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to human error, terrorist attacks, and physical or cyber security intrusions. 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 sensitive and other data 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 an enterprise resource planning system, 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.

***Transporting, distributing, and storing natural gas 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, including third party damages, 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 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 have no obligation 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.

***Failure of our counterparties to meet their obligations, including obligations under power purchase agreements, could have an adverse impact on our results of operations.***

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 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 purchasers of their obligations under the power purchase agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more purchasers could fail to perform their obligations under the power purchase agreements. If this were to occur, we would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase agreement would be reallocated among our retail customers. To the extent there is any regulatory delay in adjusting rates, a customer default under a power purchase agreement could have a negative impact on our results of operations and cash flows.

***We may not be able to 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 and adversely affect financial results.***

We assess goodwill for impairment on an annual basis or whenever events or circumstances occur that would indicate a potential for impairment. If goodwill is deemed to be impaired, we may be required to incur material non-cash charges that could materially adversely affect our results of operations. At December 31, 2017, our goodwill was \$3,053.5 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.

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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;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, and financial condition, and could limit our ability to sustain 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 "Recent 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. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us, or we may experience operational problems or constraints that prevent us from taking delivery. In addition, suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. Furthermore, demand for coal can impact its availability and cost. 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 from 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.

***The 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. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, 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.

***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. 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, except the major portion of our electric utility distribution lines, steam utility distribution mains, and natural gas utility distribution mains and services are located, for the most part, on or under streets and highways, and 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, 2017:

| Name                                  | Location             | Fuel            | Number of<br>Generating Units | Rated Capacity In<br>MW (1) |
|---------------------------------------|----------------------|-----------------|-------------------------------|-----------------------------|
| <b>Coal-fired plants</b>              |                      |                 |                               |                             |
| Columbia                              | Portage, WI          | Coal            | 2                             | 320 (2)                     |
| Edgewater                             | Sheboygan, WI        | Coal            | 1                             | 98 (2) (4)                  |
| ERGS                                  | Oak Creek, WI        | Coal            | 2                             | 1,057 (3)                   |
| Pleasant Prairie                      | Pleasant Prairie, WI | Coal            | 2                             | 1,188 (4)                   |
| PIPP                                  | Marquette, MI        | Coal            | 5                             | 359 (4)                     |
| Pulliam                               | Green Bay, WI        | Coal            | 2                             | 210 (4)                     |
| OCPP                                  | Oak Creek, WI        | Coal            | 4                             | 995                         |
| Weston                                | Rothschild, WI       | Coal            | 2                             | 708 (2)                     |
| <b>Total coal-fired plants</b>        |                      |                 | 20                            | 4,935                       |
| <b>Natural gas-fired plants</b>       |                      |                 |                               |                             |
| Concord Combustion Turbines           | Watertown, WI        | Natural Gas/Oil | 4                             | 352                         |
| De Pere Energy Center                 | De Pere, WI          | Natural Gas/Oil | 1                             | 179                         |
| Fox Energy Center                     | Wrightstown, WI      | Natural Gas     | 3                             | 571                         |
| Germantown Combustion Turbines        | Germantown, WI       | Natural Gas/Oil | 5                             | 278                         |
| Paris Combustion Turbines             | Union Grove, WI      | Natural Gas/Oil | 4                             | 352                         |
| PWGS                                  | Port Washington, WI  | Natural Gas     | 2                             | 1,182                       |
| Pulliam                               | Green Bay, WI        | Natural Gas/Oil | 1                             | 76                          |
| VAPP                                  | Milwaukee, WI        | Natural Gas     | 2                             | 240                         |
| West Marinette                        | Marinette, WI        | Natural Gas/Oil | 3                             | 155                         |
| Weston                                | Rothschild, WI       | Natural Gas/Oil | 3                             | 140                         |
| <b>Total natural gas-fired plants</b> |                      |                 | 28                            | 3,525                       |
| <b>Renewables</b>                     |                      |                 |                               |                             |
| Hydro Plants (30 in number)           | WI and MI            | Hydro           | 81                            | 151 (5)                     |
| Rothschild Biomass Plant              | Rothschild, WI       | Biomass         | 1                             | 50                          |
| Blue Sky Green Field                  | Fond du Lac, WI      | Wind            | 88                            | 21                          |
| Byron Wind Turbines                   | Fond du Lac, WI      | Wind            | 2                             | —                           |
| Crane Creek                           | Howard County, IA    | Wind            | 66                            | 20                          |
| Glacier Hills                         | Cambria, WI          | Wind            | 90                            | 28                          |
| Lincoln                               | Kewaunee County, WI  | Wind            | 14                            | 1                           |
| Montfort Wind Energy Center           | Montfort, WI         | Wind            | 20                            | 2                           |
| <b>Total renewables</b>               |                      |                 | 362                           | 273                         |
| <b>Total system</b>                   |                      |                 | 410                           | 8,733                       |

(1) Based on expected capacity ratings for summer 2018, which can differ from nameplate capacity, especially on wind projects. 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.

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- (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 and Edgewater units. WPS holds a 29.5% ownership interest in Columbia and a 31.8% ownership interest in Edgewater. See Note 5, Property, Plant, and Equipment, for more information about the retirement of Edgewater. See Note 6, Jointly Owned Facilities, for more information on the 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 holds the remaining 30.0% interest.
- (3) This facility is jointly owned by We Power and two other unaffiliated entities. The capacity indicated for the facility is equal to We Power's portion of total plant capacity based on its 83.34% ownership.
- (4) We have announced plans for the retirement of Pleasant Prairie, PIPP, Pulliam Units 7 and 8, and the jointly-owned Edgewater 4 generating unit. The Pleasant Prairie power plant is scheduled to be shut down in April 2018; therefore, rated capacity on that plant is based on capacity ratings for summer 2017. See Note 5, Property, Plant, and Equipment, for more information on the plant retirements.
- (5) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50.0% ownership interest in WRPC and is entitled to 50.0% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 8.6 MW, and WPS's share of capacity for Petenwell is 10.2 MW.

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. See Note 2, Acquisitions, for more information on the pending acquisition.

As of December 31, 2017, we operated approximately 37,100 miles of overhead distribution lines and 32,500 miles of underground distribution cable, as well as approximately 500 distribution substations and 495,500 line transformers.

## **Natural Gas Facilities**

At December 31, 2017, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 47,900 miles of natural gas distribution mains,
- Approximately 1,200 miles of natural gas transmission mains,
- Approximately 2.3 million natural gas lateral services,
- Approximately 500 natural gas distribution and transmission gate stations,
- Underground natural gas storage fields located in southeastern Michigan totaling 23.2 billion cubic feet,
- A 2.9 billion-cubic-foot underground natural gas storage field located in southern Michigan,
- A 38.3 billion-cubic-foot underground natural gas storage field located in central Illinois,
- A 2.0 billion-cubic-foot liquefied natural gas 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
- Liquefied natural gas 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 ANR Pipeline Company, Consumers Energy, Great Lakes Transmission Company, Guardian Pipeline L.L.C., Michigan Consolidated Gas Company, Natural Gas Pipeline Company of America, Northern Natural Pipeline Company, Union Gas, Vector Pipeline Company, and Viking Gas Transmission. Our liquefied natural gas storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

PGL owns and operates a reservoir in central Illinois (Manlove Field), and a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. The underground storage reservoir also serves NSG under a contractual arrangement. PGL uses its natural gas storage and pipeline assets as a natural gas hub in the Chicago area.

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, 2017, 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. CORPORATE AND OTHER**

As of December 31, 2017, the corporate and other segment facilities consisted of energy asset facilities owned by PDL.

The energy asset facilities owned by PDL include a portfolio of residential solar facilities and a portfolio of commercial and industrial solar facilities. The solar facilities consist of distributed solar projects ranging from small residential roof top systems up to commercial and industrial solar systems of 4.5 MW in size. The total capacity of these solar projects is 27.5 MW. The majority of the solar facilities are wholly owned by subsidiaries of PDL while one is jointly owned by PDL and Duke Energy Generation Services. PDL's portion of the jointly owned solar capacity is 0.4 MW.

## **ITEM 3. LEGAL PROCEEDINGS**

The following should be read in conjunction with Note 21, Commitments and Contingencies, and Note 23, 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 21, Commitments and Contingencies, Note 23, 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 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**

### ***Sheboygan River Matter***

We were contacted by the United States Department of Justice in March 2016 to commence discussions between WPS and the federal natural resource trustees to resolve WPS's alleged liability for natural resources damages (NRD) in the Sheboygan River related to the former Camp Marina manufactured gas plant site. WPS was originally notified about this claim in September 2012, but the WDNR chose not to be a party to the NRD claim negotiation in February 2014. However, the National Oceanic and Atmospheric Administration has co-equal trusteeship with the WDNR over the impacted Sheboygan River natural resources and pursued the NRD claim. Substantial remediation of the uplands at the legacy Sheboygan Camp Marina manufactured gas plant site has already occurred. We agreed to settle this matter, and the settlement documents were filed with the United States District Court for the Eastern District of Wisconsin in December 2017. The terms of the settlement will not have a material impact on our financial statements.

### ***Manlove Field Matter***

In September 2017, the Illinois Department of Natural Resources (DNR), Office of Oil and Gas Resource Management, issued a NOV to PGL related to a leak of natural gas that PGL identified at its Manlove Gas Storage Field in December 2016. PGL quickly contained the leak after it was discovered. The leak resulted in the migration of natural gas from a well located at the facility to the Mahomet Aquifer located in central Illinois, which may have impacted residential freshwater wells. PGL has been working with the potentially impacted homeowners and other residents that may have been impacted by the natural gas leak, as well as the Illinois DNR and other state agencies to investigate and remediate the impacts of the gas leak to the Mahomet Aquifer. In October 2017, the Illinois

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Attorney General (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 interim order with the State of Illinois in October 2017 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively. In addition, in December 2017, the Illinois Environmental Protection Agency served a NOV to PGL alleging the same violations as the AG.

In the complaint, as is customary in these types of actions, the AG cited to the statutory penalties allowed by law. Ultimately, the assessment of any penalties is at the AG's discretion. In the event the AG wishes to consider 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.

## EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, and positions of our executive officers at December 31, 2017 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.** <sup>(1)(2)</sup> Age 67.

- WEC Energy Group — Chairman of the Board and Chief Executive Officer from May 2004 to May 2016, and October 2017 to present. Non-Executive Chairman of the Board from May 2016 to October 2017. Director since December 2003. President from April 2003 to August 2013.
- WE — Chairman of the Board from May 2004 to May 2016. Chief Executive Officer from August 2003 to May 2016. Director from December 2003 to May 2016. President from August 2003 to June 2015.

**Allen L. Leverett.** <sup>(1)(2)</sup> Age 51.

- WEC Energy Group — President since August 2013. Chief Executive Officer from May 2016 to October 2017. Director since January 2016. Executive Vice President from May 2004 to July 2013. Chief Financial Officer from July 2003 to February 2011.
- WE — Chairman of the Board and Chief Executive Officer from May 2016 to December 31, 2017. Director from June 2015 to January 2018. President from June 2015 to May 2016. Executive Vice President from May 2004 to June 2015. Chief Financial Officer from July 2003 to February 2011.

**J. Kevin Fletcher.** Age 59.

- WE — President since May 2016. Director since June 2015. 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 51.

- 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 48.

- 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.** <sup>(3)</sup> Age 53.

- WEC Energy Group — Executive Vice President since September 2017.
- 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.

**J. Patrick Keyes.** Age 52.

- WEC Energy Group — Executive Vice President - Strategy since April 2016. Executive Vice President and Chief Financial Officer from September 2012 to March 2016. Treasurer from April 2011 to January 2013.
- WE — Director from June 2015 to April 2016. Executive Vice President and Chief Financial Officer from September 2012 to March 2016. Treasurer from April 2011 to January 2013.

**Scott J. Lauber.** Age 52.

- WEC Energy Group — Executive Vice President and Chief Financial Officer since April 2016. Vice President and Treasurer from February 2013 to March 2016. Assistant Treasurer from March 2011 to January 2013.
- WE — Director and Executive Vice President and Chief Financial Officer since April 2016. Vice President and Treasurer from February 2013 to March 2016. Assistant Treasurer from March 2011 to January 2013.

**Susan H. Martin.** <sup>(3)</sup> Age 65.

- WEC Energy Group — Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.

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- WE — Director since June 2015. Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.

**Charles R. Matthews.** Age 61.

- 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.** <sup>(4)</sup> Age 50.

- WE — Executive Vice President - Generation since April 2016. Senior Vice President - Power Generation from January 2014 to March 2016. Vice President - Oak Creek Campus from February 2011 to December 2013.

**James A. Schubilske.** Age 52.

- WEC Energy Group — Vice President and Treasurer since April 2016. Assistant Treasurer from June 2000 to January 2013.
- WE — Vice President and Treasurer since April 2016. Vice President - State Regulatory Affairs from February 2013 to March 2016. Assistant Treasurer from June 2000 to January 2013.

**Joan M. Shafer.** <sup>(5)</sup> Age 64.

- WE — Executive Vice President - Human Resources and Organizational Effectiveness since June 2015. Senior Vice President - Customer Services from January 2012 to June 2015.

**Mary Beth Straka.** Age 53.

- 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 our other significant subsidiaries.

(1) On October 12, 2017, we filed a Form 8-K to disclose that Mr. Leverett had suffered a stroke. The Board of Directors of WEC Energy Group appointed Mr. Klappa to act as Chief Executive Officer of WEC Energy Group until such time as Mr. Leverett is able to resume those responsibilities.

(2) Mr. Klappa became Chairman of the Board and Chief Executive Officer of WE effective January 1, 2018. Mr. Klappa was also appointed to the WE Board of Directors effective January 1, 2018.

(3) In July 2017, we announced Ms. Martin's intent to retire in early 2018. As part of that transition, effective January 1, 2018, Ms. Kelsey was appointed Executive Vice President, General Counsel, and Corporate Secretary of WEC Energy Group and WE, and Ms. Martin was appointed Executive Vice President of WEC Energy Group and WE. Also effective January 1, 2018, Ms. Kelsey became a Director of WE and Ms. Martin resigned as a Director of WE.

(4) Mr. Metcalfe was elected to the WE Board of Directors effective January 15, 2018.

(5) Ms. Shafer announced that she will be retiring effective May 1, 2018.

**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, 2018, based upon the number of WEC Energy Group shareholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 50,000 registered shareholders.

**Common Stock Listing and Trading**

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

**Dividends and Common Stock Prices*****Common Stock Dividends of WEC Energy Group***

Cash dividends on our common stock, as declared by our Board of Directors, are normally paid on or about the first day of March, June, September, and December of each year. 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 information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note 9, Common Equity.

On January 18, 2018, the Board of Directors increased the quarterly dividend to \$0.5525 per share effective with the first quarter of 2018 dividend payment, which equates to an annual dividend of \$2.21 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65.0–70.0% of earnings.

***Range of WEC Energy Group Common Stock Prices and Dividends***

| Quarter       | 2017            |                 |                 | 2016            |                 |                 |
|---------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
|               | High            | Low             | Dividend        | High            | Low             | Dividend        |
| First         | \$ 61.53        | \$ 56.05        | \$ 0.520        | \$ 60.16        | \$ 50.44        | \$ 0.495        |
| Second        | \$ 64.37        | \$ 59.61        | 0.520           | \$ 65.30        | \$ 55.46        | 0.495           |
| Third         | \$ 67.20        | \$ 60.47        | 0.520           | \$ 66.10        | \$ 59.03        | 0.495           |
| Fourth        | \$ 70.09        | \$ 62.84        | 0.520           | \$ 60.13        | \$ 53.66        | 0.495           |
| <b>Annual</b> | <b>\$ 70.09</b> | <b>\$ 56.05</b> | <b>\$ 2.080</b> | <b>\$ 66.10</b> | <b>\$ 50.44</b> | <b>\$ 1.980</b> |

## ITEM 6. SELECTED FINANCIAL DATA

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

| As of or for Year Ended December 31<br>(in millions, except per share information) | 2017 <sup>(1)</sup> | 2016       | 2015 <sup>(2)</sup> | 2014       | 2013       |
|--|---------------------|------------|---------------------|------------|------------|
| Operating revenues   | \$ 7,648.5          | \$ 7,472.3 | \$ 5,926.1          | \$ 4,997.1 | \$ 4,519.0 |
| Net income attributed to common shareholders                                       | 1,203.7             | 939.0      | 638.5               | 588.3      | 577.4      |
| Total assets   | 31,590.5            | 30,123.2   | 29,355.2            | 14,905.0   | 14,443.2   |
| Preferred stock of subsidiary  | 30.4                | 30.4       | 30.4                | 30.4       | 30.4       |
| Long-term debt (excluding current portion)   | 8,746.6             | 9,158.2    | 9,124.1             | 4,170.7    | 4,347.0    |
| Weighted average common shares outstanding   |                     |            |                     |            |            |
| Basic  | 315.6               | 315.6      | 271.1               | 225.6      | 227.6      |
| Diluted  | 317.2               | 316.9      | 272.7               | 227.5      | 229.7      |
| Earnings per share   |                     |            |                     |            |            |
| Basic  | \$ 3.81             | \$ 2.98    | \$ 2.36             | \$ 2.61    | \$ 2.54    |
| Diluted  | \$ 3.79             | \$ 2.96    | \$ 2.34             | \$ 2.59    | \$ 2.51    |
| Dividends per share of common stock  | \$ 2.08             | \$ 1.98    | \$ 1.74             | \$ 1.56    | \$ 1.45    |

(1) Includes the impact of the enactment of the Tax Legislation. See Note 13, Income Taxes, for more information.

(2) Includes the impact of the Integrys acquisition for the last two quarters of 2015. See Note 2, Acquisitions, for more information.

## 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 and Bluewater, which owns underground natural gas storage facilities in Michigan.

#### 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 will balance 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 with a goal of reducing CO<sub>2</sub> emissions by approximately 40% below 2005 levels by 2030. We expect to retire approximately 1,800 MW of coal generation by 2020, and add additional natural gas-fired generating units and renewable generation, including utility-scale solar projects. See Note 5, Property, Plant, and Equipment, for information related to the planned retirements of certain of our coal-fueled power plants.

#### *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 being recognized by PA Consulting Group, an independent consulting firm, as the most reliable utility in the United States in 2017 and, for the seventh year in a row, as the most reliable utility in the Midwest.

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

- Upper Michigan Energy Resources Corporation (UMERC), our Michigan electric and natural gas utility, is moving forward with its long-term generation solution for electric reliability in the Upper Peninsula of Michigan. The plan calls for UMEREC to construct and operate approximately 180 MW of natural gas-fueled generation located in the Upper Peninsula. The new generation is expected to achieve commercial operation in 2019 and provide the region with affordable, reliable electricity that generates less emissions than the Presque Isle Power Plant (PIPP). This should allow for the retirement of PIPP no later than 2020. We began site preparation work for this new generation in October 2017. For more information, see Note 23, Regulatory Environment.
- 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.
- Wisconsin Public Service Corporation (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. WPS, Wisconsin Electric Power Company and Wisconsin Gas LLC 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 made further investments at the Elm Road Generating Station in 2017 to enable the facility to burn coal from the Powder River Basin located in the western United States. The plant was originally designed to burn coal mined from the eastern United States. This project is creating flexibility and has enabled the plant to operate at lower costs, placing it in a better position to be called upon in the MISO Energy Markets, resulting in lower fuel costs for our customers.

We also made 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 and improving business processes and consolidating our IT infrastructure across all of our companies. We expect these efforts to continue to drive operational efficiency and to put us in position to effectively support plans for future growth.

## **Financial Discipline**

A strong adherence to financial discipline is essential to meeting our earnings projections and maintaining a strong balance sheet, stable cash flows, a growing dividend, and quality credit ratings.

We 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 natural gas storage facilities in Michigan and a portion of a wind energy generation facility in Wisconsin.
- See Note 3, Dispositions, for information on the sale of Integrys Transportation Fuels, LLC, the Milwaukee County Power Plant, certain assets of Wisvest LLC, and Bostco LLC's real estate holdings.

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 almost \$12 billion from 2018 to 2022. Specific projects are discussed in more detail below under Liquidity and Capital Resources.

From 2018 to 2022, we expect capital contributions to ATC and ATC Holdco to be approximately \$280 million. ATC Holdco is a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. Capital investments at ATC and ATC Holdco will be funded utilizing these capital contributions, in addition to cash generated from operations and debt. We currently forecast that our share of ATC's and ATC Holdco's projected capital expenditures over the next five years will be \$1.3 billion inside the traditional ATC footprint and \$300 million outside of the traditional ATC footprint.

## **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.

One example of how we obtain feedback from our customers is through our "We Care" calls, through which employees of our utility subsidiaries contact customers after a completed service call. Customer satisfaction is a priority, and making "We Care" calls is one of the main methods we use to gauge our performance to improve customer satisfaction.

## **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

### Consolidated Earnings

The following table compares our consolidated results:

| <i>(in millions, except per share data)</i>         | Year Ended December 31 |                 |                 |
|---|------------------------|-----------------|-----------------|
|   | 2017                   | 2016            | 2015            |
| Wisconsin   | \$ 1,065.9             | \$ 1,027.0      | \$ 884.2        |
| Illinois  | 273.0                  | 239.6           | 78.1            |
| Other states  | 54.2                   | 49.9            | 6.0             |
| Non-utility energy infrastructure                   | 400.5                  | 375.6           | 373.4           |
| Corporate and other                                 | (8.4)                  | (10.0)          | (91.2)          |
| Total operating income                              | 1,785.2                | 1,682.1         | 1,250.5         |
| Equity in earnings of transmission affiliates       | 154.3                  | 146.5           | 96.1            |
| Other income, net                                   | 64.6                   | 80.8            | 58.9            |
| Interest expense                                    | 415.7                  | 402.7           | 331.4           |
| Income before income taxes                          | 1,588.4                | 1,506.7         | 1,074.1         |
| Income tax expense                                  | 383.5                  | 566.5           | 433.8           |
| Preferred stock dividends of subsidiary             | 1.2                    | 1.2             | 1.8             |
| <b>Net income attributed to common shareholders</b> | <b>\$ 1,203.7</b>      | <b>\$ 939.0</b> | <b>\$ 638.5</b> |
| <b>Diluted earnings per share</b>                   | <b>\$ 3.79</b>         | <b>\$ 2.96</b>  | <b>\$ 2.34</b>  |

### 2017 Compared with 2016

Earnings increased \$264.7 million during 2017, compared with 2016. The significant factors impacting the increase in earnings were:

- A \$206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation.
- A \$38.9 million pre-tax (\$23.3 million after tax) increase in operating income at the Wisconsin segment, driven by lower operating expenses. A decrease in electric margins, driven by lower sales volumes, partially offset the decrease in operating expenses.
- A \$33.4 million pre-tax (\$20.0 million after tax) 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 and lower operating expenses.
- A \$24.9 million pre-tax (\$14.9 million after tax) increase in operating income at the non-utility energy infrastructure segment. The increase was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE and the inclusion of the operations of Bluewater following its acquisition on June 30, 2017.

These increases in earnings were partially offset by a \$16.2 million pre-tax (\$9.7 million after-tax) decrease in other income, net. The decrease was primarily driven by the year-over-year impact of the gains recognized in 2016 related to the repurchase of a portion of Integry's 2006 Junior Notes and the sale of certain assets of Wisvest. See Note 3, Dispositions, for information on the Wisvest sale.

### 2016 Compared with 2015

Earnings increased \$300.5 million in 2016, driven by a \$201.7 million increase in earnings due to the inclusion of a full year of Integry's results for 2016, compared to six months of Integry's results for 2015. Integry was acquired on June 29, 2015. See Note 2, Acquisitions, for more information.

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The most significant factor driving the remaining \$98.8 million increase in earnings was a \$104.1 million pre-tax (\$80.1 million after tax) decrease in acquisition costs in 2016.

### Non-GAAP Financial Measure

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 more meaningful basis for evaluating utility operations than operating revenues 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 three 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

For the periods presented in this Annual Report on Form 10-K, our Wisconsin operations included operations of WE and WG for all periods, operations for WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries, and operations for UMERC beginning January 1, 2017, due to the transfer of customers and assets in the Upper Peninsula of Michigan from WE and WPS.

| <i>(in millions)</i>                   | Year Ended December 31 |            |            |
|--|------------------------|------------|------------|
|  | 2017                   | 2016       | 2015       |
| Electric revenues                      | \$ 4,559.0             | \$ 4,628.1 | \$ 4,068.5 |
| Fuel and purchased power               | 1,467.0                | 1,473.1    | 1,369.3    |
| Total electric margins                 | 3,092.0                | 3,155.0    | 2,699.2    |
| Natural gas revenues                   | 1,270.2                | 1,177.6    | 1,122.6    |
| Cost of natural gas sold               | 701.8                  | 621.2      | 640.5      |
| Total natural gas margins              | 568.4                  | 556.4      | 482.1      |
| Total electric and natural gas margins | 3,660.4                | 3,711.4    | 3,181.3    |
| Other operation and maintenance        | 1,912.5                | 2,025.4    | 1,741.0    |
| Depreciation and amortization          | 523.9                  | 496.6      | 408.6      |
| Property and revenue taxes             | 158.1                  | 162.4      | 147.5      |
| Operating income                       | \$ 1,065.9             | \$ 1,027.0 | \$ 884.2   |

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

| <i>(in millions)</i>   | Year Ended December 31 |                   |                   |
|--|------------------------|-------------------|-------------------|
|  | 2017                   | 2016              | 2015              |
| Operation and maintenance not included in line items below   | \$ 822.6               | \$ 881.9          | \$ 744.2          |
| We Power (1)   | 513.0                  | 513.2             | 510.7             |
| Transmission (2)   | 407.4                  | 423.2             | 341.3             |
| Regulatory amortizations and other pass through expenses (3) | 158.1                  | 157.4             | 144.8             |
| Earnings sharing mechanisms                                  | 2.9                    | 24.4              | —                 |
| Other  | 8.5                    | 25.3              | —                 |
| <b>Total other operation and maintenance</b>                 | <b>\$ 1,912.5</b>      | <b>\$ 2,025.4</b> | <b>\$ 1,741.0</b> |

(1) Represents costs associated with the We Power generation units, including operating and maintenance costs incurred by WE, as well as the lease payments that are billed from We Power to WE and then recovered in WE's rates. During 2017, 2016, and 2015, \$535.1 million, \$528.4 million, and \$483.4 million, respectively, of both lease and operating and maintenance costs were billed to or incurred by WE, with the difference in costs billed or incurred and expenses recognized, either deferred or deducted from the regulatory asset.

(2) The PSCW has approved 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 2017, 2016, and 2015, \$451.4 million, \$486.0 million, and \$388.6 million, respectively, of costs were billed by transmission providers to our electric utilities.

(3) 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:

| Electric Sales Volumes            | Year Ended December 31    |                 |                 |
|-----------------------------------|---------------------------|-----------------|-----------------|
|                                   | MWh <i>(in thousands)</i> |                 |                 |
|                                   | 2017                      | 2016            | 2015            |
| <b>Customer class</b>             |                           |                 |                 |
| Residential                       | 10,636.3                  | 10,998.9        | 9,218.9         |
| Small commercial and industrial * | 12,932.1                  | 13,113.1        | 10,889.2        |
| Large commercial and industrial * | 12,822.0                  | 13,418.6        | 11,545.8        |
| Other                             | 175.6                     | 172.2           | 162.6           |
| Total retail *                    | 36,566.0                  | 37,702.8        | 31,816.5        |
| Wholesale                         | 3,768.0                   | 3,704.6         | 2,588.1         |
| Resale                            | 9,000.3                   | 8,761.6         | 9,077.1         |
| <b>Total sales in MWh *</b>       | <b>49,334.3</b>           | <b>50,169.0</b> | <b>43,481.7</b> |

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

| Natural Gas Sales Volumes    | Year Ended December 31      |                |                |
|------------------------------|-----------------------------|----------------|----------------|
|                              | Therms <i>(in millions)</i> |                |                |
|                              | 2017                        | 2016           | 2015           |
| <b>Customer class</b>        |                             |                |                |
| Residential                  | 1,039.4                     | 1,014.9        | 859.4          |
| Commercial and industrial    | 643.6                       | 610.5          | 527.4          |
| Total retail                 | 1,683.0                     | 1,625.4        | 1,386.8        |
| Transport                    | 1,316.4                     | 1,270.6        | 994.2          |
| <b>Total sales in therms</b> | <b>2,999.4</b>              | <b>2,896.0</b> | <b>2,381.0</b> |

| Weather                | Year Ended December 31 |       |       |
|------------------------|------------------------|-------|-------|
|                        | Degree Days            |       |       |
|                        | 2017                   | 2016  | 2015  |
| <b>WE and WG (1)</b>   |                        |       |       |
| Heating (6,574 normal) | 5,908                  | 6,068 | 6,468 |
| Cooling (714 normal)   | 772                    | 991   | 622   |
| <b>WPS (2)</b>         |                        |       |       |
| Heating (7,377 normal) | 6,942                  | 6,715 | 2,215 |
| Cooling (499 normal)   | 450                    | 572   | 396   |
| <b>UMERC (3)</b>       |                        |       |       |
| Heating (8,368 normal) | 8,145                  | N/A   | N/A   |
| Cooling (324 normal)   | 235                    | N/A   | N/A   |

(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. Degree days for 2015 have been included for the period from July 1, 2015, through December 31, 2015.

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

## 2017 Compared with 2016

### Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased \$63.0 million during 2017, compared with 2016. The significant factors impacting the lower electric utility margins were:

- A \$72.6 million decrease related to lower sales volumes during 2017, primarily driven by unfavorable weather as well as lower overall retail use per customer. Cooler summer and warmer winter weather in 2017, as well as an additional day of sales during 2016 due to leap year, contributed to the decrease. As measured by cooling degree days, 2017 was 22.1% and 21.3% cooler than 2016 in the Milwaukee and Green Bay areas, respectively. As measured by heating degree days, 2017 was 2.6% warmer than the same period in 2016 in the Milwaukee area.
- A \$25.9 million decrease related to SSR payments WE refunded to MISO as directed by a FERC order received in October 2017. The FERC order reduced the costs eligible for reimbursement to WE for the operation and maintenance of its PIPP units under an SSR agreement between MISO and WE. A portion of these payments was returned to WE through the MISO allocation process and reduced transmission expense as discussed below. See Note 23, Regulatory Environment, for more information.
- A \$3.5 million decrease in steam margins driven by the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information.
- A \$3.3 million period-over-period negative impact from collections of fuel and purchased power costs compared with costs approved in rates. Under the Wisconsin fuel rules, the margins of our electric utilities are impacted by under- or over-collections of certain fuel and purchased power costs that are less than a 2% price variance from the costs included in rates, and the remaining variance that exceeds the 2% variance is deferred.

These decreases in margins were partially offset by \$36.5 million of lower capacity payments to a counterparty during 2017, related to improved contract terms.

### Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased \$12.0 million during 2017, compared with 2016. The most significant factor impacting the higher natural gas utility margins was higher retail sales volumes, primarily driven by higher overall retail use per customer and customer growth. The higher margins were partially offset by an additional day of sales during 2016 due to leap year.

## Operating Income

Operating income at the Wisconsin segment increased \$38.9 million during 2017, compared with 2016. This increase was driven by \$89.9 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), partially offset by the \$51.0 million net decrease in margins discussed above.

The Wisconsin segment experienced lower overall operating expenses related to synergy savings resulting from the Integrys acquisition. The significant factors impacting the decrease in operating expenses during 2017, compared with 2016, which were due in part to synergy savings, were:

- A \$29.1 million decrease in electric and natural gas distribution expenses, primarily related to lower metering costs and other cost savings.
- A \$21.5 million decrease in expenses related to the earnings sharing mechanisms in place at WE and WG. See the PSCW conditions of approval related to the Integrys acquisition in Note 2, Acquisitions, for more information.
- A \$16.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A \$15.8 million decrease in transmission expenses, driven by a FERC order to reduce SSR costs related to PIPP, as discussed under electric utility margins.
- An \$11.5 million decrease in expenses related to an information technology project completed in 2016 to improve the billing, call center, and credit collection functions of certain WEC Energy Group subsidiaries. Lower expenses were due in part to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including WPS, during 2017. The portion of these lower expenses related to the transfer is offset through higher depreciation and amortization, discussed below.
- A \$10.5 million decrease in operation and maintenance expenses at our plants, primarily related to the seasonal operation of the Pleasant Prairie power plant during 2017, lower operating costs at the plants, the timing of planned outages and maintenance, and the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information on the sale of the MCPP. These decreases were partially offset by severance costs related to plant retirement. See Note 5, Property, Plant, and Equipment, for more information on the plants to be retired.
- A \$5.7 million decrease in customer service expenses, partially related to lower contracted meter reading rates and cost savings.

These decreases in operating expenses were partially offset by:

- A \$27.3 million increase in depreciation and amortization, driven by an overall increase in utility plant in service, the completion of the ReACT™ multi-pollutant control system at Weston Unit 3 during the fourth quarter of 2016, and WBS's transfer of the information technology project to WPS during 2017.
- A \$10.9 million gain recorded in April 2016 related to the sale of the MCPP. See Note 3, Dispositions, for more information on the sale of the MCPP.

## 2016 Compared with 2015

### Electric Utility Margins

Electric utility margins at the Wisconsin segment increased \$455.8 million during 2016, compared with 2015. The increase was primarily driven by a \$386.4 million margin contribution from WPS during the first six months of 2016, compared with no margin contribution from WPS for the first six months of 2015.

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The significant factors impacting the remaining \$69.4 million increase in electric utility margins at the Wisconsin segment were:

- A \$50.4 million increase related to higher retail sales volumes during 2016, primarily driven by warmer summer weather. As measured by cooling degree days, 2016 was 59.3% warmer than 2015 in the Milwaukee area.
- The expiration of \$12.5 million of bill credits refunded to customers in 2015 related to the Treasury Grant WE received in connection with its biomass facility.
- An \$11.3 million increase in the last six months of 2016 as a result of WPS's PSCW rate order, effective January 1, 2016. See Note 23, Regulatory Environment, for more information.

These increases were partially offset by a \$12.9 million decrease in wholesale margins driven by a reduction in capacity sales year-over-year at WE in addition to a reduction in sales volumes at WPS for the second half of 2016, compared with the same period in 2015. Certain wholesale customers have provisions in their contracts, which allowed them to reduce the amount of energy we provided to them.

### **Natural Gas Utility Margins**

Natural gas utility margins at the Wisconsin segment increased \$74.3 million during 2016, compared with 2015. The increase in natural gas utility margins was driven by a \$63.6 million margin contribution from WPS during the first six months of 2016, compared with no margin contribution from WPS for the first six months of 2015.

The most significant factor impacting the remaining \$10.7 million increase in natural gas utility margins at the Wisconsin segment was an \$18.1 million net increase from both WG's rate order effective January 1, 2016, and a partially offsetting negative impact from WPS's rate order during the last six months of 2016. See Note 23, Regulatory Environment, for more information. This net increase was partially offset by a \$3.2 million decrease related to lower sales volumes during 2016, primarily driven by warmer winter weather. As measured by heating degree days, 2016 was 6.2% warmer than 2015 in the Milwaukee area.

### **Operating Income**

Operating income at the Wisconsin segment increased \$142.8 million during 2016, compared with 2015. The increase was driven by the \$530.1 million increase in margins discussed above, partially offset by \$387.3 million of higher operating expenses. Higher operating expenses were driven by \$321.6 million of operating expenses from WPS during the first six months of 2016, compared with no operating expenses from WPS for the first six months of 2015.

The significant factors impacting the remaining \$65.7 million increase in operating expenses during 2016, compared with 2015, at the Wisconsin segment were:

- A \$27.0 million increase in depreciation and amortization, driven by an overall increase in utility plant in service. In November 2015, WG completed the Western Gas lateral project, and WE completed the conversion of the fuel source for VAPP from coal to natural gas.
- A \$25.3 million increase in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A \$24.4 million expense related to the earnings sharing mechanisms in place at WE and WG, effective January 1, 2016.

These increases in operating expenses were partially offset by a \$16.4 million positive impact at WE from the sale of the MCPP in April 2016, including a gain on sale and lower operating costs in 2016.

## Illinois Segment Contribution to Operating Income

We did not have any operations in Illinois until our acquisition of Integrys on June 29, 2015. 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.

| <i>(in millions)</i>            | Year Ended December 31 |                 |                |
|---------------------------------|------------------------|-----------------|----------------|
|                                 | 2017                   | 2016            | 2015           |
| Natural gas revenues            | \$ 1,355.5             | \$ 1,242.2      | \$ 503.4       |
| Cost of natural gas sold        | 438.9                  | 365.2           | 133.2          |
| Total natural gas margins       | 916.6                  | 877.0           | 370.2          |
| Other operation and maintenance | 471.1                  | 485.1           | 219.6          |
| Depreciation and amortization   | 152.6                  | 134.0           | 63.3           |
| Property and revenue taxes      | 19.9                   | 18.3            | 9.2            |
| <b>Operating income</b>         | <b>\$ 273.0</b>        | <b>\$ 239.6</b> | <b>\$ 78.1</b> |

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

| <i>(in millions)</i>   | Year Ended December 31 |                 |                 |
|--|------------------------|-----------------|-----------------|
|  | 2017                   | 2016            | 2015            |
| Operation and maintenance not included in the line items below | \$ 368.4               | \$ 385.3        | \$ 196.0        |
| Riders *   | 98.1                   | 82.3            | 20.2            |
| Regulatory amortizations *                                     | 1.0                    | 2.7             | 1.3             |
| Other  | 3.6                    | 14.8            | 2.1             |
| <b>Total other operation and maintenance</b>                   | <b>\$ 471.1</b>        | <b>\$ 485.1</b> | <b>\$ 219.6</b> |

\* 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:

| Natural Gas Sales Volumes    | Therms <i>(in millions)</i> |                |              |
|------------------------------|-----------------------------|----------------|--------------|
|                              | 2017                        | 2016           | 2015         |
| <b>Customer Class</b>        |                             |                |              |
| Residential                  | 886.2                       | 905.6          | 300.7        |
| Commercial and industrial    | 183.6                       | 187.6          | 63.2         |
| Total retail                 | 1,069.8                     | 1,093.2        | 363.9        |
| Transport                    | 858.8                       | 855.3          | 328.4        |
| <b>Total sales in therms</b> | <b>1,928.6</b>              | <b>1,948.5</b> | <b>692.3</b> |

| Weather *              | Degree Days |       |       |
|------------------------|-------------|-------|-------|
|                        | 2017        | 2016  | 2015  |
| Heating (6,110 normal) | 5,470       | 5,713 | 1,813 |

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

## 2017 Compared with 2016

### Natural Gas Utility Margins

Natural gas utility margins, net of the \$15.8 million impact of the riders referenced in the table above, increased \$23.8 million during 2017, compared with 2016. 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.

## **Operating Income**

Operating income at the Illinois segment increased \$33.4 million during 2017, compared with 2016. This increase was due to the \$23.8 million net increase in margins discussed above and a \$9.6 million decrease in operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes), net of the impact of the riders referenced in the table above. The significant factors impacting the decrease in operating expenses were:

- A \$21.1 million decrease in benefit related expenses driven by lower pension costs.
- A \$9.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.
- A \$6.0 million decrease in expenses related to an information technology project created to improve the billing, call center, and credit collection functions of certain WEC Energy Group subsidiaries. Lower expenses were primarily due to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including PGL and NSG, during 2017. Lower expenses related to the transfer are offset through higher depreciation and amortization, discussed below.

These decreases were partially offset by:

- An \$18.6 million increase in depreciation and amortization expense, driven by continued capital investment at PGL in the SMP project and the transfer of the information technology project to PGL and NSG in 2017.
- A \$3.4 million increase in natural gas distribution expenses, driven by increased repair activity in 2017.

## **2016 Compared with 2015**

### **Natural Gas Utility Margins**

Natural gas utility margins at the Illinois segment increased \$506.8 million during 2016, compared with 2015. The increase was primarily driven by a \$467.8 million margin contribution from the Illinois segment during the first six months of 2016, compared to no margin contribution from this segment for the first six months of 2015.

The significant factors impacting the remaining \$39.0 million increase in natural gas utility margins at the Illinois segment were:

- A \$26.3 million increase in margins related to the riders referenced in the table above during the last six months of 2016, compared with the last six months of 2015.
- A \$10.8 million increase in revenue at PGL due to continued capital investment in projects under its QIP rider.

### **Operating Income**

Operating income at the Illinois segment increased \$161.5 million during 2016, compared with 2015. The increase was primarily driven by the \$506.8 million increase in margin discussed above, partially offset by:

- Operating expenses of \$308.2 million during the first six months of 2016, compared with no operating expenses during the first six months of 2015.
- A \$26.3 million increase in other operation and maintenance expenses related to the riders referenced in the table above during the last six months of 2016, compared with the last six months of 2015.
- A \$9.7 million increase in other operation and maintenance expenses during the last six months of 2016 compared with the last six months of 2015, due to an increase in expenses related to charitable projects supporting our customers and the communities within our service territories.

## Other States Segment Contribution to Operating Income

We did not have any operations in this segment until our acquisition of Integrys on June 29, 2015. 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.

| <i>(in millions)</i>            | Year Ended December 31 |                |               |
|---------------------------------|------------------------|----------------|---------------|
|                                 | 2017                   | 2016           | 2015          |
| Natural gas revenues            | \$ 411.2               | \$ 376.5       | \$ 149.3      |
| Cost of natural gas sold        | 215.3                  | 182.3          | 76.9          |
| Total natural gas margins       | 195.9                  | 194.2          | 72.4          |
| Other operation and maintenance | 101.3                  | 110.1          | 50.0          |
| Depreciation and amortization   | 24.8                   | 21.1           | 10.0          |
| Property and revenue taxes      | 15.6                   | 13.1           | 6.4           |
| <b>Operating income</b>         | <b>\$ 54.2</b>         | <b>\$ 49.9</b> | <b>\$ 6.0</b> |

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

| <i>(in millions)</i>                                       | Year Ended December 31 |                 |                |
|--|------------------------|-----------------|----------------|
|  | 2017                   | 2016            | 2015           |
| Operation and maintenance not included in line items below | \$ 78.3                | \$ 86.4         | \$ 43.2        |
| Regulatory amortizations and other pass through expenses * | 23.0                   | 23.6            | 6.7            |
| Other  | —                      | 0.1             | 0.1            |
| <b>Total other operation and maintenance</b>               | <b>\$ 101.3</b>        | <b>\$ 110.1</b> | <b>\$ 50.0</b> |

\* 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:

| Natural Gas Sales Volumes    | Therms <i>(in millions)</i> |                |              |
|------------------------------|-----------------------------|----------------|--------------|
|                              | 2017                        | 2016           | 2015         |
| <b>Customer Class</b>        |                             |                |              |
| Residential                  | 285.6                       | 278.5          | 84.7         |
| Commercial and industrial    | 199.4                       | 178.2          | 60.9         |
| Total retail                 | 485.0                       | 456.7          | 145.6        |
| Transport                    | 693.3                       | 696.2          | 279.6        |
| <b>Total sales in therms</b> | <b>1,178.3</b>              | <b>1,152.9</b> | <b>425.2</b> |

| Weather *              | Degree Days |       |       |
|------------------------|-------------|-------|-------|
|                        | 2017        | 2016  | 2015  |
| <b>MERC</b>            |             |       |       |
| Heating (7,907 normal) | 7,625       | 7,188 | 2,563 |
| <b>MGU</b>             |             |       |       |
| Heating (6,244 normal) | 5,707       | 5,712 | 1,822 |

\* 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.

## 2017 Compared with 2016

### Operating Income

Operating income at the other states segment increased \$4.3 million during 2017, compared with 2016. The increase was primarily driven by lower operation and maintenance expense due to effective cost control measures, partially offset by higher depreciation and amortization due to an increase in capital investment.

## 2016 Compared with 2015

### Natural Gas Utility Margins

Natural gas utility margins at the other states segment increased \$121.8 million during 2016, compared with 2015. The increase was primarily driven by a \$110.4 million margin contribution from the other states segment during the first six months of 2016, compared to no margin contribution from this segment for the first six months of 2015.

The significant factors impacting the remaining \$11.4 million increase in natural gas utility margins at the other states segment were:

- A \$3.9 million increase in the last six months of 2016 as a result of various rate orders. An interim rate order for MERC was effective January 1, 2016, and accounted for \$2.5 million of the rate increase. The MGU rate order was also effective January 1, 2016, and accounted for \$1.4 million of the rate increase. See Note 23, Regulatory Environment, for more information.
- A \$3.0 million increase related to higher sales volumes during the last six months of 2016, driven by colder weather. As measured by heating degree days, the last six months of 2016 were 11.5% colder than the last six months of 2015 at MGU and 5.7% colder than the last six months of 2015 at MERC.
- A \$1.6 million increase related to the MERC conservation improvement program financial incentive as a result of exceeding certain energy savings goals.

### Operating Income

Operating income at the other states segment increased \$43.9 million during 2016, compared with 2015. The increase was driven by the \$121.8 million increase in margins discussed above, partially offset by \$77.9 million of higher operating expenses. Higher operating expenses were driven primarily by \$76.3 million of operating expenses from the other states segment during the first six months of 2016, compared with no operating expenses during the first six months of 2015.

## Non-Utility Energy Infrastructure Segment Contribution to Operating Income

| (in millions)    | Year Ended December 31 |          |          |
|------------------|------------------------|----------|----------|
|                  | 2017                   | 2016     | 2015     |
| Operating income | \$ 400.5               | \$ 375.6 | \$ 373.4 |

## 2017 Compared with 2016

Operating income at the non-utility energy infrastructure segment increased \$24.9 million during 2017, compared with 2016. Bluewater, which was acquired on June 30, 2017, contributed \$8.4 million to 2017 operating income. The remaining increase of \$16.5 million was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE. See Note 2, Acquisitions, for more information on the acquisition of Bluewater and Note 19, Segment Information, for information on the change in segment name.

## 2016 Compared with 2015

Operating income at the non-utility energy infrastructure segment increased \$2.2 million during 2016, compared with 2015. This increase was primarily related to higher revenues in connection with capital additions to the plants We Power owns and leases to WE.

**Corporate and Other Segment Contribution to Operating Income**

| <i>(in millions)</i> | Year Ended December 31 |           |           |
|----------------------|------------------------|-----------|-----------|
|                      | 2017                   | 2016      | 2015      |
| Operating loss       | \$ (8.4)               | \$ (10.0) | \$ (91.2) |

**2017 Compared with 2016**

The operating loss at the corporate and other segment decreased \$1.6 million during 2017, compared with 2016, driven by \$3.5 million of costs incurred in 2016 related to the acquisition of Integrys. See Note 2, Acquisitions, for more information regarding costs associated with the acquisition.

**2016 Compared with 2015**

The operating loss at the corporate and other segment decreased \$81.2 million during 2016, compared with 2015, driven by a reduction in costs related to the acquisition of Integrys.

**Electric Transmission Segment Operations**

| <i>(in millions)</i>                          | Year Ended December 31 |          |         |
|---|------------------------|----------|---------|
|   | 2017                   | 2016     | 2015    |
| Equity in earnings of transmission affiliates | \$ 154.3               | \$ 146.5 | \$ 96.1 |

**2017 Compared with 2016**

Earnings from our ownership interests in transmission affiliates increased \$7.8 million during 2017, compared with 2016. The lower earnings during 2016 as compared to 2017 were primarily the result of an ALJ recommendation related to the FERC ROE complaints. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

**2016 Compared with 2015**

Earnings from our ownership interests in transmission affiliates increased \$50.4 million during 2016, compared with 2015, primarily due to the increase in our ownership interest from 26.2% to approximately 60% as a result of the acquisition of Integrys on June 29, 2015. In addition, the lower earnings during 2015 were also driven by an ALJ initial decision issued in December 2015 related to the ATC ROE complaints, which was later affirmed by a FERC order in 2016.

**Consolidated Other Income, Net**

| <i>(in millions)</i>        | Year Ended December 31 |                |                |
|-----------------------------|------------------------|----------------|----------------|
|                             | 2017                   | 2016           | 2015           |
| AFUDC – Equity              | \$ 11.4                | \$ 25.1        | \$ 20.1        |
| Gain on repurchase of notes | —                      | 23.6           | —              |
| Gain on asset sales         | 1.9                    | 19.6           | 22.9           |
| Other, net                  | 51.3                   | 12.5           | 15.9           |
| <b>Other income, net</b>    | <b>\$ 64.6</b>         | <b>\$ 80.8</b> | <b>\$ 58.9</b> |

**2017 Compared with 2016**

Other income, net decreased \$16.2 million during 2017, compared with 2016. This decrease was primarily driven by the \$23.6 million gain recorded in February 2016 on the repurchase of a portion of Integrys's 2006 Junior Notes at a discount, the \$19.6 million gain recorded in April 2016 from the sale of the chilled water generation and distribution assets of Wisvest, and lower AFUDC in 2017 largely due to the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016. Partially offsetting these decreases were higher gains on investments held in our rabbi trust during 2017, compared

with 2016. See Note 12, Long-Term Debt and Capital Lease Obligations, for more information on the note repurchase and Note 3, Dispositions, for information on our asset sales.

### 2016 Compared with 2015

Other income, net increased \$21.9 million during 2016, compared with 2015. This increase was primarily driven by the repurchase of a portion of Integrys's 2006 Junior Notes at a discount in February 2016, as well as higher AFUDC in 2016 due to the inclusion of AFUDC from the Integrys companies post acquisition. Partially offsetting these increases was a \$19.6 million gain recorded in April 2016 from the sale of the chilled water generation and distribution assets of Wisvest, compared with a \$20.8 million gain from the sale of Minergy LLC and its remaining financial assets in June 2015, as well as excise tax credits recognized by ITF in 2015. ITF was sold in the first quarter of 2016.

### Consolidated Interest Expense

| <i>(in millions)</i> | Year Ended December 31 |          |          |
|----------------------|------------------------|----------|----------|
|                      | 2017                   | 2016     | 2015     |
| Interest expense     | \$ 415.7               | \$ 402.7 | \$ 331.4 |

### 2017 Compared with 2016

Interest expense increased \$13.0 million during 2017, compared with 2016. The increase was primarily due to higher debt levels in 2017 to fund continued capital investments and lower capitalized interest during 2017, primarily as a result of the completion of the ReACT™ emission control project in 2016.

### 2016 Compared with 2015

Interest expense increased \$71.3 million during 2016, compared with 2015. The increase was primarily driven by \$68.5 million of interest expense from Integrys and its subsidiaries during the first six months of 2016, compared to no interest expense from these companies during the same period in 2015. Additionally, we issued \$1.2 billion of long-term debt in June 2015 to finance a portion of the cash consideration for the acquisition of Integrys. This was offset, in part, by the repurchase of a portion of the 2006 Junior Notes in February 2016. These notes were replaced with lower-interest rate short-term debt.

### Consolidated Income Tax Expense

|                    | Year Ended December 31 |       |       |
|--------------------|------------------------|-------|-------|
|                    | 2017                   | 2016  | 2015  |
| Effective tax rate | 24.1%                  | 37.6% | 40.4% |

### 2017 Compared with 2016

Our effective tax rate was 24.1% in 2017 compared to 37.6% in 2016. This decrease was driven by a \$206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation. Our effective tax rate in 2017 excluding the one-time net reduction in income tax expense due to revaluation of our deferred taxes was 37.2%. Preliminarily, we expect our 2018 annual effective tax rate to be between 15% and 16%, which includes an estimated 7% effective tax rate benefit due to the flow through of tax repairs in connection with the Wisconsin settlement. See Note 23, Regulatory Environment, for more information on the Wisconsin settlement. Excluding the impact of the tax repairs, the 2018 range would be between 22% and 23%. See Note 13, Income Taxes, for more information.

### 2016 Compared with 2015

Our effective tax rate was 37.6% in 2016 compared to 40.4% in 2015. This decrease was primarily related to a charge in 2015 to remeasure our state deferred income taxes as a result of the acquisition of Integrys.

**LIQUIDITY AND CAPITAL RESOURCES****Cash Flows**

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

| <i>(in millions)</i>               | 2017       | 2016       | 2015       | Change in 2017 Over<br>2016 | Change in 2016 Over<br>2015 |
|------------------------------------|------------|------------|------------|-----------------------------|-----------------------------|
| <b>Cash provided by (used in):</b> |            |            |            |                             |                             |
| Operating activities               | \$ 2,079.6 | \$ 2,103.5 | \$ 1,293.6 | \$ (23.9)                   | \$ 809.9                    |
| Investing activities               | (2,239.6)  | (1,270.1)  | (2,517.5)  | (969.5)                     | 1,247.4                     |
| Financing activities               | 161.4      | (845.7)    | 1,211.8    | 1,007.1                     | (2,057.5)                   |

**Operating Activities****2017 Compared with 2016**

Net cash provided by operating activities decreased \$23.9 million during 2017, compared with 2016, driven by:

- A \$217.9 million decrease in cash resulting from higher payments for natural gas and fuel and purchased power in 2017, primarily due to higher commodity prices. The average per-unit cost of natural gas sold increased 13.6% during 2017, compared with 2016.
- A \$91.8 million increase in contributions and payments to our pension and OPEB plans during 2017, compared with 2016.
- A \$34.5 million net decrease in cash received from income taxes during 2017, compared with 2016. This decrease in cash was primarily due to the extension of bonus depreciation in December 2015, which resulted in the receipt of an income tax refund during 2016.
- A \$26.5 million decrease in cash due to higher collateral requirements during 2017, compared with 2016, driven by a decrease in the fair value of our derivative instruments. See Note 15, Derivative Instruments, for more information.

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

- A \$158.7 million increase in cash from lower payments for operating and maintenance costs. During 2017, our payments related to transmission, electric and natural gas distribution, charitable projects, employee benefits, and electric generation decreased.
- A \$129.2 million increase in cash related to higher overall collections from customers, primarily due to higher commodity prices during 2017, compared with 2016.
- A \$49.6 million increase in cash distributions provided by ATC during 2017, compared with 2016.

**2016 Compared with 2015**

Net cash provided by operating activities increased \$809.9 million during 2016, compared with 2015. This increase was driven by \$466.6 million of net cash flows from the operating activities of Integrys during the first six months of 2016 since Integrys was acquired on June 29, 2015. See Note 2, Acquisitions, for more information.

The remaining \$343.3 million increase in net cash provided by operating activities was driven by:

- A \$377.9 million increase in cash resulting from lower payments for natural gas and fuel and purchased power in 2016, due to lower commodity prices and warmer weather during the 2016 heating season. The average per-unit cost of natural gas sold decreased 18.5% during 2016.
- A \$94.2 million decrease in contributions and payments to our pension and OPEB plans during 2016, compared with 2015.

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- A \$44.1 million increase in cash due to lower collateral requirements during 2016, compared with 2015, driven by an increase in the fair value of our derivative instruments.
- A \$29.2 million increase in cash received from income taxes, primarily due to a Wisconsin state income tax refund received in the fourth quarter of 2016.

These increases in net cash provided by operating activities were partially offset by a \$210.8 million decrease in cash related to lower overall collections from customers. Collections from customers decreased primarily because of lower commodity prices and warmer weather during the 2016 heating season.

## **Investing Activities**

### **2017 Compared with 2016**

Net cash used in investing activities increased \$969.5 million during 2017, compared with 2016, driven by:

- A \$535.8 million increase in cash paid for capital expenditures during 2017, compared with 2016, which is discussed in more detail below.
- The acquisition of Bluewater during June 2017 for \$226.0 million. See Note 2, Acquisitions, for more information.
- A \$142.3 million decrease in the proceeds received from the sale of assets and businesses during 2017, compared with 2016. See Note 3, Dispositions, for more information.
- A \$67.3 million increase in our capital contributions to ATC and ATC Holdco during 2017, compared with 2016, due to the continued investment in equipment and facilities by ATC to improve reliability and the restructuring of DATC's ownership. During the fourth quarter of 2017, ATC Holdco purchased ATC's ownership interest in DATC, which resulted in an increase in our capital contributions. In addition, the refunds paid by ATC in 2017 and ATC's lower earnings in 2016, as a result of the ATC ROE complaints filed with the FERC, also contributed to the year-over-year increase in our capital contributions. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information on the ATC ROE complaints.

### **2016 Compared with 2015**

Net cash used in investing activities decreased \$1,247.4 million during 2016, compared with 2015, driven by:

- An investment of \$1,329.9 million in June 2015 related to the acquisition of Integrys, which is net of cash acquired of \$156.3 million. See Note 2, Acquisitions, for more information.
- A \$137.4 million increase in the proceeds received from the sale of assets and businesses during 2016, compared with 2015.

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

- A \$157.5 million increase in cash paid for capital expenditures during 2016, compared with 2015, which is discussed in more detail below.
- A \$33.6 million increase in our capital contributions to ATC during 2016, compared with 2015, driven by both the continued investment in equipment and facilities by ATC to improve reliability and the increase in our ATC ownership interest as a result of the June 2015 Integrys acquisition.

**Capital Expenditures**

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

| Reportable Segment<br>(in millions) | 2017              | 2016              | 2015              | Change in 2017 Over<br>2016 | Change in 2016 Over<br>2015 |
|-------------------------------------|-------------------|-------------------|-------------------|-----------------------------|-----------------------------|
| Wisconsin                           | \$ 1,152.3        | \$ 910.9          | \$ 950.3          | \$ 241.4                    | \$ (39.4)                   |
| Illinois                            | 545.2             | 293.2             | 194.4             | 252.0                       | 98.8                        |
| Other states                        | 74.5              | 59.5              | 34.7              | 15.0                        | 24.8                        |
| Non-utility energy infrastructure   | 35.4              | 62.3              | 53.4              | (26.9)                      | 8.9                         |
| Corporate and other                 | 152.1             | 97.8              | 33.4              | 54.3                        | 64.4                        |
| <b>Total capital expenditures</b>   | <b>\$ 1,959.5</b> | <b>\$ 1,423.7</b> | <b>\$ 1,266.2</b> | <b>\$ 535.8</b>             | <b>\$ 157.5</b>             |

**2017 Compared with 2016**

The increase in cash paid for capital expenditures at the Wisconsin segment during 2017, compared with 2016, was driven by upgrades to our electric and natural gas distribution systems, including main replacement projects and an advanced metering infrastructure program, as well as WPS's SMRP and various projects at the OCPP. These increases in capital expenditures were partially offset by reduced construction activity at WPS related to the ReACTTM emission control technology project at Weston Unit 3, which was completed in 2016, and the combustion turbine project at the Fox Energy Center, which was completed in June 2017.

The increase in cash paid for capital expenditures at the Illinois segment during 2017, compared with 2016, was driven by increased construction activity related to PGL's SMP and natural gas storage field as well as a project to relocate one of PGL's service facilities.

The increase in cash paid for capital expenditures at the other states segment during 2017, compared with 2016, was driven by upgrades to MERC's natural gas distribution systems and mains as well as the construction of an office building due to the relocation of MERC's headquarters during 2017.

The decrease in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2017, compared with 2016, was driven by reduced construction activity for We Power's fuel flexibility project at the Oak Creek Expansion units, which was completed during December 2017.

The increase in cash paid for capital expenditures at the corporate and other segment during 2017, compared with 2016, was driven by a project to implement a new enterprise resource planning system and various other software projects.

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

**2016 Compared with 2015**

The decrease in cash paid for capital expenditures at the Wisconsin segment during 2016, compared with 2015, was driven by the November 2015 completion of both WG's Western Gas Lateral project, which improved the reliability of WG's natural gas distribution network in the western part of Wisconsin, and WE's coal to natural gas conversion project at VAPP. Also contributing to the decrease were lower payments at WE for environmental compliance projects and electric distribution upgrades. The inclusion of WPS for all of 2016, as compared with only the last six months of 2015, substantially offset these lower capital expenditures. WPS's capital expenditures of \$154.1 million during the first six months of 2016 related to the ReACTTM emission control technology project at Weston Unit 3, the combustion turbine project at the Fox Energy Center, and the SMRP.

The increase in cash paid for capital expenditures at the Illinois segment during 2016, compared with 2015, was due to the inclusion of PGL and NSG for all of 2016, compared with only the last six months of 2015. Capital expenditures at the Illinois segment were driven primarily by the SMP at PGL.

The increase in cash paid for capital expenditures at the other states segment during 2016, compared with 2015, was due to the inclusion of MERC and MGU for all of 2016, compared with only the last six months of 2015. MERC's and MGU's capital expenditures of \$22.7 million during the first six months of 2016 primarily related to natural gas distribution systems and mains.

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The increase in cash paid for capital expenditures at the corporate and other segment during 2016, compared with 2015, was driven by a project to implement a new enterprise resource planning system and an information technology project created to improve the billing, call center, and credit collection functions of the Integrys subsidiaries.

## **Financing Activities**

### **2017 Compared with 2016**

Net cash related to financing activities increased \$1,007.1 million during 2017, compared with 2016, driven by:

- An \$819.2 million net increase in cash due to \$584.4 million of net borrowings of commercial paper during 2017, compared with \$234.8 million of net repayments of commercial paper during 2016.
- A \$151.5 million increase in cash related to lower long-term debt repayments during 2017, compared with 2016. In February 2016, we repurchased a portion of Integrys's 2006 Junior Notes at a discount.
- A \$36.7 million increase in cash due to fewer shares of our common stock purchased during 2017, compared with 2016, to satisfy requirements of our stock-based compensation plans.
- A \$35.0 million increase in cash due to the issuance of more long-term debt during 2017, compared with 2016.

These increases in net cash related to financing activities were partially offset by a \$31.6 million increase in dividends paid on our common stock during 2017, compared with 2016. In January 2017, our Board of Directors increased our quarterly dividend by \$0.025 per share effective with the first quarter of 2017 dividend payment.

### **2016 Compared with 2015**

Net cash related to financing activities decreased \$2,057.5 million during 2016, compared with 2015, driven by:

- A \$1,526.4 million net decrease in cash due to a \$1,750.0 million decrease in the issuance of long-term debt during 2016, partially offset by \$223.6 million of lower repayments of long-term debt during 2016. We issued \$1,200.0 million of long-term debt during 2015 in connection with the acquisition of Integrys.
- A \$397.8 million net decrease in cash due to \$234.8 million of net repayments of commercial paper during 2016, compared with \$163.0 million of net borrowings of commercial paper during 2015.
- A \$169.5 million increase in dividends paid on common stock during 2016, compared with 2015, due to the issuance of 90.2 million shares of our common stock in June 2015 as a result of the Integrys acquisition and increases to our quarterly dividend rate. See Note 2, Acquisitions, for more information.
- A \$33.3 million decrease in cash due to more shares of our common stock purchased during 2016, compared with 2015, to satisfy requirements of our stock-based compensation plans.

These decreases in net cash related to financing activities were partially offset by a \$52.7 million increase in cash due to the redemption of all of WPS's preferred stock during 2015.

### **Significant Financing Activities**

For more information on our financing activities, see Note 11, Short-Term Debt and Lines of Credit, and Note 12, Long-Term Debt and Capital Lease Obligations.

## 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 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, WG, WPS, 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 11, 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, 2017 and 2016, 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:

| <i>(in millions)</i>                       | 2017               |                    | 2016               |                    |
|--|--------------------|--------------------|--------------------|--------------------|
|  | Actual             | Adjusted           | Actual             | Adjusted           |
| Common equity                              | \$ 9,461.4         | \$ 9,711.4         | \$ 8,929.8         | \$ 9,179.8         |
| Preferred stock of subsidiary              | 30.4               | 30.4               | 30.4               | 30.4               |
| Long-term debt (including current portion) | 9,588.7            | 9,338.7            | 9,315.4            | 9,065.4            |
| Short-term debt                            | 1,444.6            | 1,444.6            | 860.2              | 860.2              |
| <b>Total capitalization</b>                | <b>\$ 20,525.1</b> | <b>\$ 20,525.1</b> | <b>\$ 19,135.8</b> | <b>\$ 19,135.8</b> |
| <br>                                       |                    |                    |                    |                    |
| Total debt                                 | \$ 11,033.3        | \$ 10,783.3        | \$ 10,175.6        | \$ 9,925.6         |
| <br>                                       |                    |                    |                    |                    |
| Ratio of debt to total capitalization      | 53.8%              | 52.5%              | 53.2%              | 51.9%              |

Included in long-term debt on our balance sheets as of December 31, 2017 and 2016, 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 by the rating agency treatment of the 2007 Junior Notes. 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 rate, maturity, and amount outstanding of each series of our long-term debt on a consolidated basis, see our capitalization statements.

As described in Note 9, 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, 2017, 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 11, Short-Term Debt and Lines of Credit, for more information about our credit facilities and other short-term credit agreements. See Note 12, Long-Term Debt and Capital Lease Obligations, for more information about our long-term debt.

## Working Capital

As of December 31, 2017, our current liabilities exceeded our current assets by \$1,655.8 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 January 2018, Moody's downgraded the rating outlook for WG to negative from stable as a result of the new Tax Legislation. We do not believe the change in rating outlook will have a material impact on our ability to access capital markets.

In July 2017, Moody's downgraded the ratings of WE (senior unsecured), WPS (senior unsecured), WG (senior unsecured), and ERGSS (senior secured) to A2 from A1. Moody's affirmed the commercial paper ratings of WE (P-1), WPS (P-1), and WG (P-1). Moody's also affirmed the ratings of WEC Energy Group (senior unsecured, A3), WECC (senior unsecured, A3), and Integrys (senior unsecured, A3), but changed the rating outlook for these companies to negative from stable. We do not believe the changes in ratings and rating outlook will have a material impact on our ability to access capital markets.

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 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 downgrading 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, 2017:

| <i>(in millions)</i>  | Payments Due by Period <sup>(1)</sup> |                   |                   |                   |                    |
|---|---------------------------------------|-------------------|-------------------|-------------------|--------------------|
|   | Total                                 | Less Than 1 Year  | 1-3 Years         | 3-5 Years         | More Than 5 Years  |
| Long-term debt obligations <sup>(2)</sup>                     | \$ 18,025.9                           | \$ 1,238.0        | \$ 1,801.1        | \$ 1,070.5        | \$ 13,916.3        |
| Capital lease obligations <sup>(3)</sup>                      | 71.4                                  | 14.7              | 31.9              | 24.8              | —                  |
| Operating lease obligations <sup>(4)</sup>                    | 115.1                                 | 9.5               | 16.8              | 14.7              | 74.1               |
| Energy and transportation purchase obligations <sup>(5)</sup> | 11,640.9                              | 1,084.2           | 1,691.4           | 1,369.7           | 7,495.6            |
| Purchase orders <sup>(6)</sup>                                | 1,168.6                               | 851.3             | 137.7             | 77.7              | 101.9              |
| Pension and OPEB funding obligations <sup>(7)</sup>           | 49.0                                  | 13.1              | 35.9              | —                 | —                  |
| <b>Total contractual obligations</b>                          | <b>\$ 31,070.9</b>                    | <b>\$ 3,210.8</b> | <b>\$ 3,714.8</b> | <b>\$ 2,557.4</b> | <b>\$ 21,587.9</b> |

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- (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 capital lease obligations). The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2017.
- (3) Capital lease obligations for power purchase commitments. This amount does not include We Power leases to WE which are eliminated upon consolidation.
- (4) Operating lease obligations for power purchase commitments and rail car leases.
- (5) Energy and transportation purchase obligations under various contracts for the procurement of fuel, power, gas supply, and associated transportation related to utility operations.
- (6) Purchase obligations related to normal business operations, information technology, and other services.
- (7) Obligations for pension and OPEB plans cannot reasonably be estimated beyond 2020.

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 13, Income Taxes.

The table above also does not reflect estimated future payments related to the manufactured gas plant remediation liability of \$617.2 million at December 31, 2017, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 21, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of \$573.7 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.

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

#### Capital Expenditures and Significant Capital Projects

We have several capital projects that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental requirements, regulatory restraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends. Our estimated capital expenditures and acquisitions for the next three years are as follows:

| <i>(in millions)</i>              | 2018              | 2019              | 2020              |
|-----------------------------------|-------------------|-------------------|-------------------|
| Wisconsin                         | \$ 1,430.1        | \$ 1,152.0        | \$ 1,850.2        |
| Illinois                          | 633.8             | 629.2             | 676.5             |
| Other states                      | 99.6              | 116.1             | 110.6             |
| Non-utility energy infrastructure | 280.8             | 60.5              | 51.9              |
| Corporate and other               | 20.7              | 13.2              | 0.8               |
| <b>Total</b>                      | <b>\$ 2,465.0</b> | <b>\$ 1,971.0</b> | <b>\$ 2,690.0</b> |

WPS is continuing work on the SMRP. 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 \$250 million between 2018 and 2022 on this project. WE, WPS, and WG will also continue to upgrade their electric and natural gas distribution systems to enhance reliability. These upgrades include the advanced metering infrastructure (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.

As part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar of up to 350 MW within our Wisconsin segment. Solar generation technology has greatly improved, has become more cost-effective, and it complements our summer demand curve.

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In connection with the formation of UMERC, we entered into an agreement with Tilden under which it will purchase electric power from UMERC for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. The new generation is expected to begin commercial operation in 2019. The estimated cost of this project is approximately \$266 million (\$277 million with AFUDC). See Note 23, Regulatory Environment, for more information about UMERC and this new generation.

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 2020 is between \$280 million and \$300 million. See Note 23, Regulatory Environment, for more information on the SMP.

We expect to provide capital contributions to ATC and ATC Holdco (not included in the above table) of approximately \$200 million from 2018 through 2020.

### **Common Stock Matters**

For information related to our common stock matters, see Note 9, Common Equity.

On January 18, 2018, our Board of Directors increased our quarterly dividend to \$0.5525 per share effective with the first quarter of 2018 dividend payment, which equates to an annual dividend of \$2.21 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 \$3.8 billion as of December 31, 2017. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed \$120.5 million, \$28.7 million, and \$121.0 million to our pension and OPEB plans in 2017, 2016, and 2015, 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 17, 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 11, Short-Term Debt and Lines of Credit, Note 16, Guarantees, and Note 20, 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 – D. 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 the 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 our 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

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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 six 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, 2017, our regulatory assets were \$2,840.4 million, and our regulatory liabilities were \$3,760.4 million.

Due to the Tax Legislation signed into law in December 2017, our regulated utilities remeasured their deferred taxes and recorded an estimated tax benefit of \$2,450 million. This tax benefit will be returned to ratepayers through future refunds, bill credits, riders, or reductions to other regulatory assets. See Note 13, Income Taxes, and Note 23, 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:

- In June 2016, the PSCW approved the deferral of costs related to WPS's ReACT™ project above the originally authorized \$275.0 million level through 2017. The total cost of the ReACT™ project, excluding \$51 million of AFUDC, is currently estimated to be \$342 million. In September 2017, the PSCW approved an extension of this deferral through 2019 as part of a settlement agreement. See Note 23, Regulatory Environment, for more information. WPS will be required to obtain a separate approval for collection of these deferred costs in a future rate case.
- Prior to its acquisition, 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, 2017, we had not received any significant disallowances of the costs incurred for this project. We will be required to obtain approval for the recovery of additional costs incurred through the completion of this long-term project.
- 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 prudence. In March 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. In 2018, PGL agreed to a settlement of the 2014 reconciliation, which includes a rate base reduction of \$5.4 million and a \$4.7 million refund to ratepayers. As of December 31, 2017, 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 23, 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 – D. 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), Revenues and Customer Receivables, 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 2017, 2016, and 2015, 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, 2017, and December 31, 2016, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by \$20.6 million and \$9.8 million in 2017 and 2016, 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:

| <i>(in millions)</i> | As of December 31,<br>2017 | Expected Return on Assets<br>in 2018 |
|----------------------|----------------------------|--------------------------------------|
| Pension trust funds  | \$ 2,966.8                 | 7.12%                                |
| OPEB trust funds     | \$ 841.5                   | 7.25%                                |

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, Michigan, and Minnesota. 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.

## **Industry Restructuring**

### ***Electric Utility Industry***

The regulated energy industry continues to experience significant changes. The FERC continues to support large RTOs, which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, 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.

#### **Restructuring in 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.

#### **Restructuring in 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, 2017, 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 from an alternative retail natural gas 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, there is little impact on our net income from customers purchasing natural gas from an alternative retail natural gas supplier as natural gas costs are passed through to customers in rates on a one-for-one basis.

#### **Restructuring in Wisconsin**

The PSCW previously instituted generic proceedings to consider how its regulation of natural gas distribution utilities should change to reflect a competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to provide customer classes with competitive market choices the option to choose an alternative retail natural gas supplier. The PSCW has also adopted standards for transactions between a utility and its natural gas marketing affiliates. All of our Wisconsin customer classes have competitive market choices and, therefore, can purchase natural gas directly from either an alternative retail natural gas supplier or their local natural gas utility. Currently, we are unable to predict the impact of potential future industry restructuring on our results of operations or financial position.

### **Restructuring in Illinois**

Since 2002, PGL and NSG have provided their customers with the option to choose an alternative retail natural gas supplier. We are not required by the ICC or state law to make this option available to customers, but since this option is currently provided to our Illinois customers, we would need ICC approval to eliminate it.

### **Restructuring in Minnesota**

MERC has provided its commercial and industrial customers with the option to choose an alternative retail natural gas supplier since 2006. We are not required by the MPUC or state law to make this 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.

### **Restructuring in Michigan**

The option to choose an alternative retail 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 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 21, 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**

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

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 October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 2013. In December 2015, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a 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 incentive adder only applies to revenues collected after January 6, 2015. In September 2016, the FERC issued a final order related to this complaint affirming the use of the ROE stated in the ALJ's initial decision, effective as of the order date, on a going-forward basis. The order also required ATC to provide refunds, with interest, for the 15-month refund period from November 12, 2013, through February 11, 2015. The refunds ATC provided to WE and WPS for transmission costs paid during the refund period reduced the regulatory assets recorded under the PSCW-approved escrow accounting for transmission expense and resulted in a net regulatory liability for WPS. See Note 18, Investment in Transmission Affiliates, for more information.

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. In June 2016, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a base ROE of 9.7%, as well as the 0.5% incentive adder approved for MISO transmission owners. The ALJ's initial decision is not binding on the FERC and applies to revenues collected from February 12, 2015, through May 11, 2016. We are uncertain when a FERC order related to this matter will be issued.

The MISO transmission owners have filed various appeals related to several of the FERC orders with the D.C. Circuit Court of Appeals as well as requests for rehearing.

The decrease in ATC's ROE resulting from the FERC's final order issued in September 2016 will continue to have a negative impact on our equity earnings and distributions from ATC.

## **Tax Cuts and Jobs Act of 2017**

On December 22, 2017, the Tax Legislation was signed into law. See Note 13, Income Taxes, and Note 23, Regulatory Environment, for more information regarding its impact on us.

### **Bonus Depreciation Provisions**

Bonus depreciation is an additional amount of first-year tax deductible depreciation that is awarded above what would normally be available. Based on the Protecting Americans from Tax Hikes Act of 2015, a 50% bonus depreciation deduction was available for assets placed in service during 2017. The increase in our federal tax depreciation from this deduction significantly reduced our 2017 federal income tax payment.

On December 22, 2017, the Tax Legislation was signed into law. This legislation modified the bonus depreciation deduction available for public utility property subject to rate-making by a government entity or public utility commission. See Note 13, Income Taxes, for more information.

### **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.

#### **Goodwill Impairment**

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments were recorded as a result of these tests. For our Bluewater reporting unit, we assumed fair value equaled carrying value since Bluewater was acquired on June 30, 2017. For all of our other reporting units that carried a goodwill balance, the fair values calculated in step one of the test were greater than their carrying values. The fair values for these 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 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 included ROEs, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and 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.

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

For all of our reporting units other than Bluewater, fair value exceeded carrying value by over 50%. For Bluewater, we assumed fair value equaled carrying value since we acquired Bluewater on June 30, 2017. 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, 2017:

| <i>(in millions, except percentages)</i> | Goodwill          | Percentage of Total Goodwill |
|--|-------------------|------------------------------|
| Wisconsin                                | \$ 2,104.3        | 68.9%                        |
| Illinois                                 | 758.7             | 24.9%                        |
| Other states                             | 183.2             | 6.0%                         |
| Bluewater                                | 7.3               | 0.2%                         |
| <b>Total goodwill</b>                    | <b>\$ 3,053.5</b> | <b>100.0%</b>                |

See Note 8, Goodwill, for more information.

### **Long-Lived Assets**

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, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

We have evaluated future plans for our older fossil fuel generating units and have announced our plans for the retirement of certain older and less-efficient generating units. 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, we assess the likelihood of recovery of the remaining carrying 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 the abandoned generating unit, an impairment charge may be required. An impairment charge would be recorded if the remaining carrying value of the abandoned generating unit is greater than the present value of the amount expected to be recovered from ratepayers.

We concluded that the Pleasant Prairie power plant, PIPP, the Pulliam power plant, and the jointly-owned Edgewater 4 generating unit meet the criteria to be considered probable of abandonment as of December 31, 2017. We plan to ask for full cost recovery of and a full return on the remaining book value of the generating units and have concluded that no impairment was required related to these assets as of December 31, 2017.

See Note 5, Property, Plant, and Equipment, for more information on the units to be retired.

### **Pension and Other Postretirement Employee Benefits**

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 17, 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.

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Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered or refunded at our utilities through the rate-making process.

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

| Actuarial Assumption<br>(in millions, except percentages) | Percentage-Point Change in Assumption | Impact on Projected Benefit Obligation | Impact on 2017 Pension Cost |
|---|---------------------------------------|--|-----------------------------|
| Discount rate   | (0.5)                                 | \$ 211.3                               | \$ 18.3                     |
| Discount rate   | 0.5                                   | (183.6)                                | (10.3)                      |
| Rate of return on plan assets                             | (0.5)                                 | N/A                                    | 13.6                        |
| Rate of return on plan assets                             | 0.5                                   | N/A                                    | (13.6)                      |

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<br>(in millions, except percentages) | Percentage-Point Change in Assumption | Impact on Postretirement Benefit Obligation | Impact on 2017 Postretirement Benefit Cost |
|---|---------------------------------------|---|--|
| Discount rate   | (0.5)                                 | \$ 56.2                                     | \$ 2.6                                     |
| Discount rate   | 0.5                                   | (49.3)                                      | (1.3)                                      |
| Health care cost trend rate                               | (0.5)                                 | (31.9)                                      | (3.3)                                      |
| Health care cost trend rate                               | 0.5                                   | 37.1  | 3.8  |
| 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 (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds across the full maturity spectrum. The bonds are generally rated "Aa" with a minimum amount outstanding of \$50.0 million. 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 7.11%, 7.12%, and 7.37%, in 2017, 2016, and 2015, respectively. The actual rate of return on pension plan assets, net of fees, was 13.74%, 7.75%, and (3.85)%, in 2017, 2016, and 2015, 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 17, Employee Benefits.

### Regulatory Accounting

Our utility operations follow the guidance under the Regulated Operations Topic of the FASB ASC. 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 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 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, 2017, we had \$2,840.4 million in regulatory assets and \$3,760.4 million in regulatory liabilities. See Note 4, Regulatory Assets and Liabilities, for more information.

### ***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 2017 of approximately \$7.6 billion included accrued utility revenues of \$538.1 million as of December 31, 2017.

### ***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 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 the provision for income taxes in the 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 13, 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 16, 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 and statements of capitalization of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, 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 28, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

#### Basis for Opinion

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

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

#### /s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin  
February 28, 2018

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, 2017, based on the 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, 2017, based on the 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, 2017, of the Company and our report dated February 28, 2018 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

### Basis for Opinion

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

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

### Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the 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 28, 2018

**B. CONSOLIDATED INCOME STATEMENTS**

| Year Ended December 31<br>(in millions, except per share amounts) | 2017              | 2016            | 2015            |
|---|-------------------|-----------------|-----------------|
| <b>Operating revenues</b>   | \$ 7,648.5        | \$ 7,472.3      | \$ 5,926.1      |
| <b>Operating expenses</b>   |                   |                 |                 |
| Cost of sales   | 2,822.8           | 2,647.4         | 2,240.1         |
| Other operation and maintenance                                   | 2,047.0           | 2,185.5         | 1,709.3         |
| Depreciation and amortization                                     | 798.6             | 762.6           | 561.8           |
| Property and revenue taxes  | 194.9             | 194.7           | 164.4           |
| <b>Total operating expenses</b>                                   | <b>5,863.3</b>    | <b>5,790.2</b>  | <b>4,675.6</b>  |
| <b>Operating income</b>   | <b>1,785.2</b>    | <b>1,682.1</b>  | <b>1,250.5</b>  |
| Equity in earnings of transmission affiliates                     | 154.3             | 146.5           | 96.1            |
| Other income, net   | 64.6              | 80.8            | 58.9            |
| Interest expense  | 415.7             | 402.7           | 331.4           |
| <b>Other expense</b>  | <b>(196.8)</b>    | <b>(175.4)</b>  | <b>(176.4)</b>  |
| Income before income taxes  | 1,588.4           | 1,506.7         | 1,074.1         |
| Income tax expense  | 383.5             | 566.5           | 433.8           |
| <b>Net income</b>   | <b>1,204.9</b>    | <b>940.2</b>    | <b>640.3</b>    |
| Preferred stock dividends of subsidiary                           | 1.2               | 1.2             | 1.8             |
| <b>Net income attributed to common shareholders</b>               | <b>\$ 1,203.7</b> | <b>\$ 939.0</b> | <b>\$ 638.5</b> |
| <b>Earnings per share</b>   |                   |                 |                 |
| Basic   | \$ 3.81           | \$ 2.98         | \$ 2.36         |
| Diluted   | \$ 3.79           | \$ 2.96         | \$ 2.34         |
| <b>Weighted average common shares outstanding</b>                 |                   |                 |                 |
| Basic   | 315.6             | 315.6           | 271.1           |
| Diluted   | 317.2             | 316.9           | 272.7           |

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

**C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| Year Ended December 31<br>(in millions)   | 2017              | 2016            | 2015            |
|---|-------------------|-----------------|-----------------|
| <b>Net income</b>   | \$ 1,204.9        | \$ 940.2        | \$ 640.3        |
| <b>Other comprehensive (loss) income, net of tax</b>  |                   |                 |                 |
| <b>Derivatives accounted for as cash flow hedges</b>  |                   |                 |                 |
| Gains on settlement, net of tax of \$7.6  | —                 | —               | 11.4            |
| Reclassification of gains to net income, net of tax   | (1.3)             | (1.3)           | (0.8)           |
| <b>Cash flow hedges, net</b>  | <b>(1.3)</b>      | <b>(1.3)</b>    | <b>10.6</b>     |
| <b>Defined benefit plans</b>  |                   |                 |                 |
| Pension and OPEB adjustments arising during the period, net of tax of \$0.6, \$0.1, and \$(4.2), respectively | 0.9               | (0.8)           | (6.3)           |
| Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax                      | 0.4               | 0.4             | —               |
| <b>Defined benefit plans, net</b>   | <b>1.3</b>        | <b>(0.4)</b>    | <b>(6.3)</b>    |
| <b>Other comprehensive (loss) income, net of tax</b>  | <b>—</b>          | <b>(1.7)</b>    | <b>4.3</b>      |
| <b>Comprehensive income</b>   | <b>1,204.9</b>    | <b>938.5</b>    | <b>644.6</b>    |
| Preferred stock dividends of subsidiary   | 1.2               | 1.2             | 1.8             |
| <b>Comprehensive income attributed to common shareholders</b>   | <b>\$ 1,203.7</b> | <b>\$ 937.3</b> | <b>\$ 642.8</b> |

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

**D. CONSOLIDATED BALANCE SHEETS**

| At December 31<br>(in millions, except share and per share amounts)  | 2017               | 2016               |
|--|--------------------|--------------------|
| <b>Assets</b>  |                    |                    |
| <b>Current assets</b>  |                    |                    |
| Cash and cash equivalents  | \$ 38.9            | \$ 37.5            |
| Accounts receivable and unbilled revenues, net of reserves of \$143.2 and \$108.0, respectively                              | 1,350.7            | 1,241.7            |
| Materials, supplies, and inventories   | 539.0              | 587.6              |
| Prepayments  | 210.0              | 204.4              |
| Other  | 74.9               | 97.5               |
| <b>Current assets</b>  | <b>2,213.5</b>     | <b>2,168.7</b>     |
| <b>Long-term assets</b>  |                    |                    |
| Property, plant, and equipment, net of accumulated depreciation of \$8,618.5 and \$8,214.6, respectively                     | 21,347.0           | 19,915.5           |
| Regulatory assets  | 2,803.2            | 3,087.9            |
| Equity investment in transmission affiliates   | 1,553.4            | 1,443.9            |
| Goodwill   | 3,053.5            | 3,046.2            |
| Other  | 619.9              | 461.0              |
| <b>Long-term assets</b>  | <b>29,377.0</b>    | <b>27,954.5</b>    |
| <b>Total assets</b>  | <b>\$ 31,590.5</b> | <b>\$ 30,123.2</b> |
| <b>Liabilities and Equity</b>  |                    |                    |
| <b>Current liabilities</b>   |                    |                    |
| Short-term debt  | \$ 1,444.6         | \$ 860.2           |
| Current portion of long-term debt  | 842.1              | 157.2              |
| Accounts payable   | 859.9              | 861.5              |
| Accrued payroll and benefits   | 169.1              | 163.8              |
| Other  | 553.6              | 388.9              |
| <b>Current liabilities</b>   | <b>3,869.3</b>     | <b>2,431.6</b>     |
| <b>Long-term liabilities</b>   |                    |                    |
| Long-term debt   | 8,746.6            | 9,158.2            |
| Deferred income taxes  | 2,999.8            | 5,146.6            |
| Deferred revenue, net  | 543.3              | 566.2              |
| Regulatory liabilities   | 3,718.6            | 1,563.8            |
| Environmental remediation liabilities  | 617.4              | 633.6              |
| Pension and OPEB obligations   | 397.4              | 498.6              |
| Other  | 1,206.3            | 1,164.4            |
| <b>Long-term liabilities</b>   | <b>18,229.4</b>    | <b>18,731.4</b>    |
| Commitments and contingencies (Note 21)  |                    |                    |
| <b>Common shareholders' equity</b>   |                    |                    |
| Common stock – \$0.01 par value; 325,000,000 shares authorized; 315,574,624 and 315,614,941 shares outstanding, respectively | 3.2                | 3.2                |
| Additional paid in capital   | 4,278.5            | 4,309.8            |
| Retained earnings  | 5,176.8            | 4,613.9            |
| Accumulated other comprehensive income   | 2.9                | 2.9                |
| <b>Common shareholders' equity</b>   | <b>9,461.4</b>     | <b>8,929.8</b>     |
| Preferred stock of subsidiary  | 30.4               | 30.4               |
| <b>Total liabilities and equity</b>  | <b>\$ 31,590.5</b> | <b>\$ 30,123.2</b> |

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



**E. CONSOLIDATED STATEMENTS OF CASH FLOWS**

| Year Ended December 31<br>(in millions)                                | 2017             | 2016             | 2015             |
|--|------------------|------------------|------------------|
| <b>Operating activities</b>  |                  |                  |                  |
| Net income   | 1,204.9          | \$ 940.2         | \$ 640.3         |
| Reconciliation to cash provided by operating activities                |                  |                  |                  |
| Depreciation and amortization  | 798.6            | 762.6            | 583.5            |
| Deferred income taxes and investment tax credits, net                  | 271.7            | 493.8            | 418.7            |
| Contributions and payments related to pension and OPEB plans           | (120.5)          | (28.7)           | (121.0)          |
| Equity income in transmission affiliates, net of distributions         | (4.8)            | (46.6)           | (11.0)           |
| Change in –  |                  |                  |                  |
| Accounts receivable and unbilled revenues                              | (86.4)           | (180.7)          | 84.0             |
| Materials, supplies, and inventories                                   | 49.3             | 100.0            | (69.4)           |
| Other current assets   | (6.0)            | 103.1            | (27.2)           |
| Accounts payable   | 8.5              | 34.4             | (9.3)            |
| Other current liabilities  | 161.8            | (20.8)           | 14.1             |
| Other, net   | (197.5)          | (53.8)           | (209.1)          |
| <b>Net cash provided by operating activities</b>                       | <b>2,079.6</b>   | <b>2,103.5</b>   | <b>1,293.6</b>   |
| <b>Investing activities</b>  |                  |                  |                  |
| Capital expenditures   | (1,959.5)        | (1,423.7)        | (1,266.2)        |
| Integrus acquisition, net of cash acquired of \$156.3                  | –                | –                | (1,329.9)        |
| Bluewater acquisition  | (226.0)          | –                | –                |
| Capital contributions to transmission affiliates                       | (109.6)          | (42.3)           | (8.7)            |
| Proceeds from the sale of assets and businesses                        | 24.0             | 166.3            | 28.9             |
| Withdrawal of restricted cash from Rabbi trust for qualifying payments | 19.5             | 26.6             | 1.4              |
| Other, net   | 12.0             | 3.0              | 57.0             |
| <b>Net cash used in investing activities</b>                           | <b>(2,239.6)</b> | <b>(1,270.1)</b> | <b>(2,517.5)</b> |
| <b>Financing activities</b>  |                  |                  |                  |
| Exercise of stock options  | 30.8             | 41.6             | 30.1             |
| Purchase of common stock   | (71.3)           | (108.0)          | (74.7)           |
| Dividends paid on common stock   | (656.5)          | (624.9)          | (455.4)          |
| Redemption of WPS preferred stock                                      | –                | –                | (52.7)           |
| Issuance of long-term debt   | 435.0            | 400.0            | 2,150.0          |
| Retirement of long-term debt   | (154.5)          | (306.0)          | (529.6)          |
| Change in short-term debt  | 584.4            | (234.8)          | 163.0            |
| Other, net   | (6.5)            | (13.6)           | (18.9)           |
| <b>Net cash provided by (used in) financing activities</b>             | <b>161.4</b>     | <b>(845.7)</b>   | <b>1,211.8</b>   |
| <b>Net change in cash and cash equivalents</b>                         | <b>1.4</b>       | <b>(12.3)</b>    | <b>(12.1)</b>    |
| Cash and cash equivalents at beginning of year                         | 37.5             | 49.8             | 61.9             |
| <b>Cash and cash equivalents at end of year</b>                        | <b>\$ 38.9</b>   | <b>\$ 37.5</b>   | <b>\$ 49.8</b>   |

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

**F. CONSOLIDATED STATEMENTS OF EQUITY**

| <i>(in millions, expect per share amounts)</i>            | WEC Energy Group Common Shareholders' Equity |                            |                   |  |                                   |                               |              |
|---|--|----------------------------|-------------------|--|-----------------------------------|-------------------------------|--------------|
|   | Common Stock                                 | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | Total Common Shareholders' Equity | Preferred Stock of Subsidiary | Total Equity |
| <b>Balance at December 31, 2014</b>                       | \$ 2.3                                       | \$ 300.1                   | \$ 4,117.0        | \$ 0.3                                 | \$ 4,419.7                        | \$ 30.4                       | \$ 4,450.1   |
| Net income attributed to common shareholders              | —  | —                          | 638.5             | —                                      | 638.5                             | —                             | 638.5        |
| Other comprehensive income                                | —  | —                          | —                 | 4.3                                    | 4.3                               | —                             | 4.3          |
| Common stock dividends of \$1.74 per share                | —  | —                          | (455.4)           | —                                      | (455.4)                           | —                             | (455.4)      |
| Exercise of stock options                                 | —  | 30.1                       | —                 | —                                      | 30.1                              | —                             | 30.1         |
| Issuance of common stock for the acquisition of Integrys  | 0.9  | 4,072.0                    | —                 | —                                      | 4,072.9                           | —                             | 4,072.9      |
| Purchase of common stock                                  | —  | (74.7)                     | —                 | —                                      | (74.7)                            | —                             | (74.7)       |
| Addition of WPS preferred stock                           | —  | —                          | —                 | —                                      | —                                 | 51.1                          | 51.1         |
| Redemption of WPS preferred stock                         | —  | (1.6)                      | —                 | —                                      | (1.6)                             | (51.1)                        | (52.7)       |
| Stock-based compensation and other                        | —  | 21.3                       | (0.3)             | —                                      | 21.0                              | —                             | 21.0         |
| <b>Balance at December 31, 2015</b>                       | \$ 3.2                                       | \$ 4,347.2                 | \$ 4,299.8        | \$ 4.6                                 | \$ 8,654.8                        | \$ 30.4                       | \$ 8,685.2   |
| Net income attributed to common shareholders              | —  | —                          | 939.0             | —                                      | 939.0                             | —                             | 939.0        |
| Other comprehensive loss                                  | —  | —                          | —                 | (1.7)                                  | (1.7)                             | —                             | (1.7)        |
| Common stock dividends of \$1.98 per share                | —  | —                          | (624.9)           | —                                      | (624.9)                           | —                             | (624.9)      |
| Exercise of stock options                                 | —  | 41.6                       | —                 | —                                      | 41.6                              | —                             | 41.6         |
| Purchase of common stock                                  | —  | (108.0)                    | —                 | —                                      | (108.0)                           | —                             | (108.0)      |
| Stock-based compensation and other                        | —  | 29.0                       | —                 | —                                      | 29.0                              | —                             | 29.0         |
| <b>Balance at December 31, 2016</b>                       | \$ 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 adoption of ASU 2016-09 | —  | —                          | 15.7              | —                                      | 15.7                              | —                             | 15.7         |
| Stock-based compensation and other                        | —  | 9.2                        | —                 | —                                      | 9.2                               | —                             | 9.2          |
| <b>Balance at December 31, 2017</b>                       | \$ 3.2                                       | \$ 4,278.5                 | \$ 5,176.8        | \$ 2.9                                 | \$ 9,461.4                        | \$ 30.4                       | \$ 9,491.8   |

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

**G. CONSOLIDATED STATEMENTS OF CAPITALIZATION**

| At December 31  |                      |                          |       | 2017       | 2016       |
|---|----------------------|--------------------------|-------|------------|------------|
| <i>(in millions)</i>  |                      |                          |       |            |            |
| Common shareholder's equity (see accompanying statement)        |                      |                          |       | \$ 9,461.4 | \$ 8,929.8 |
| Preferred stock of subsidiary (Note 10)                         |                      |                          |       | 30.4       | 30.4       |
| <b>Long-term debt</b>   | <b>Interest Rate</b> | <b>Year Due</b>          |       |            |            |
| WEC Energy Group Senior Notes (unsecured)                       | 1.65%                | 2018                     | 300.0 | 300.0      |            |
|   | 2.45%                | 2020                     | 400.0 | 400.0      |            |
|   | 3.55%                | 2025                     | 500.0 | 500.0      |            |
|   | 6.20%                | 2033                     | 200.0 | 200.0      |            |
| WEC Energy Group Junior Notes (unsecured) <sup>(1)</sup>        | 3.53%                | 2067                     | 500.0 | 500.0      |            |
| WE Debentures (unsecured)                                       | 1.70%                | 2018                     | 250.0 | 250.0      |            |
|   | 4.25%                | 2019                     | 250.0 | 250.0      |            |
|   | 2.95%                | 2021                     | 300.0 | 300.0      |            |
|   | 3.10%                | 2025                     | 250.0 | 250.0      |            |
|   | 6.50%                | 2028                     | 150.0 | 150.0      |            |
|   | 5.625%               | 2033                     | 335.0 | 335.0      |            |
|   | 5.70%                | 2036                     | 300.0 | 300.0      |            |
|   | 3.65%                | 2042                     | 250.0 | 250.0      |            |
|   | 4.25%                | 2044                     | 250.0 | 250.0      |            |
|   | 4.30%                | 2045                     | 250.0 | 250.0      |            |
|   | 6.875%               | 2095                     | 100.0 | 100.0      |            |
| WPS Senior Notes (unsecured)                                    | 5.65%                | 2017                     | —     | 125.0      |            |
|   | 1.65%                | 2018                     | 250.0 | 250.0      |            |
|   | 6.08%                | 2028                     | 50.0  | 50.0       |            |
|   | 5.55%                | 2036                     | 125.0 | 125.0      |            |
|   | 3.671%               | 2042                     | 300.0 | 300.0      |            |
|   | 4.752%               | 2044                     | 450.0 | 450.0      |            |
| WG Debentures (unsecured)                                       | 3.53%                | 2025                     | 200.0 | 200.0      |            |
|   | 5.90%                | 2035                     | 90.0  | 90.0       |            |
|   | 3.71%                | 2046                     | 200.0 | 200.0      |            |
| PGL First and Refunding Mortgage Bonds (secured) <sup>(2)</sup> | 8.00%                | 2018                     | 5.0   | 5.0        |            |
|   | 4.63%                | 2019                     | 75.0  | 75.0       |            |
|   | 3.90%                | 2030                     | 50.0  | 50.0       |            |
|   | 1.875%               | 2033                     | 50.0  | 50.0       |            |
|   | 4.00%                | 2033                     | 50.0  | 50.0       |            |
|   | 3.98%                | 2042                     | 100.0 | 100.0      |            |
|   | 3.96%                | 2043                     | 220.0 | 220.0      |            |
|   | 4.21%                | 2044                     | 200.0 | 200.0      |            |
|   | 3.65%                | 2046                     | 50.0  | 50.0       |            |
|   | 3.65%                | 2046                     | 150.0 | 150.0      |            |
|   | 3.77%                | 2047                     | 100.0 | —          |            |
| NSG First Mortgage Bonds (secured) <sup>(3)</sup>               | 3.43%                | 2027                     | 28.0  | 28.0       |            |
|   | 3.96%                | 2043                     | 54.0  | 54.0       |            |
| MGU Senior Notes (unsecured)                                    | 3.11%                | 2027                     | 30.0  | —          |            |
|   | 3.41%                | 2032                     | 30.0  | —          |            |
|   | 4.01%                | 2047                     | 30.0  | —          |            |
| MERC Senior Notes (unsecured)                                   | 3.11%                | 2027                     | 40.0  | —          |            |
|   | 3.41%                | 2032                     | 40.0  | —          |            |
|   | 4.01%                | 2047                     | 40.0  | —          |            |
| Bluewater Gas Storage Senior Notes (unsecured)                  | 3.76%                | 2018-2047                | 125.0 | —          |            |
| We Power Subsidiaries Notes (secured, nonrecourse)              | 4.91%                | <sup>(4)</sup> 2018-2030 | 101.0 | 106.7      |            |
|   | 5.209%               | <sup>(5)</sup> 2018-2030 | 194.1 | 204.8      |            |
|   | 4.673%               | <sup>(5)</sup> 2018-2031 | 162.4 | 170.9      |            |
|   | 6.00%                | <sup>(4)</sup> 2018-2033 | 121.5 | 126.1      |            |



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| Long-term debt (continued)                                      | Interest Rate | Year Due      | 2017               | 2016               |
|---|---------------|---------------|--------------------|--------------------|
| We Power Subsidiaries Notes (secured, nonrecourse) (continued)  | 6.09%         | (5) 2030-2040 | 275.0              | 275.0              |
|   | 5.848%        | (5) 2031-2041 | 215.0              | 215.0              |
| WECC Notes (unsecured)  | 6.94%         | 2028          | 50.0               | 50.0               |
| IntegrYS Senior Notes (unsecured)                               | 4.17%         | 2020          | 250.0              | 250.0              |
| IntegrYS Junior Notes (unsecured)                               | 3.60%         | (6) 2066      | 114.9              | 114.9              |
|   | 6.00%         | 2073          | 400.0              | 400.0              |
| Other Notes (secured, nonrecourse)                              | 4.81%         | 2030          | —                  | 2.0                |
| Obligations under capital leases                                |               |               | 27.0               | 29.6               |
| <b>Total</b>  |               |               | <b>9,627.9</b>     | <b>9,352.0</b>     |
| IntegrYS acquisition fair value adjustment                      |               |               | 26.9               | 33.3               |
| Unamortized debt issuance costs                                 |               |               | (38.0)             | (38.1)             |
| Unamortized discount, net and other                             |               |               | (28.1)             | (31.8)             |
| <b>Total long-term debt, including current portion</b>          |               |               | <b>9,588.7</b>     | <b>9,315.4</b>     |
| Current portion of long-term debt and capital lease obligations |               |               | (842.1)            | (157.2)            |
| <b>Total long-term debt</b>                                     |               |               | <b>8,746.6</b>     | <b>9,158.2</b>     |
| <b>Total long-term capitalization</b>                           |               |               | <b>\$ 18,238.4</b> | <b>\$ 18,118.4</b> |

(1) Variable interest rate reset quarterly. The rate was 3.53% as of December 31, 2017. Prior to May 15, 2017, fixed rate of 6.25%.

(2) 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.

(3) 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.

(4) We Power senior notes, secured by a collateral assignment of the leases between PWGS and WE related to PWGS 1 and PWGS 2.

(5) We Power senior notes, secured by a collateral assignment of the leases between ERGSS and WE related to ER 1 and ER 2.

(6) Variable interest rate reset quarterly. At December 31, 2017 and 2016, the rate was 3.60% and 3.05%, respectively.

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

## H. 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 2.8 million natural gas customers, and it 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, statements of equity, and statements of capitalization, unless otherwise noted.

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, WG, and WPS, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin, and UMERG, which includes WE's electric operations and WPS's electric and natural gas operations in the state of Michigan that were transferred to UMERG effective January 1, 2017.
- 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 federally regulated electric transmission company.
- 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. See Note 2, Acquisitions, for more information on the June 2017 Bluewater transaction.
- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLG holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. See Note 3, Dispositions, for more information on these sales.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 6, Jointly Owned Facilities, for more information. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. 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.

**(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) Revenues and Customer Receivables**—We recognize revenues related to the sale of energy on the accrual basis and include estimated amounts for services provided but not yet billed to customers.

We present revenues net of pass-through taxes on the income statements.

Below is a summary of the significant mechanisms our utility subsidiaries had in place that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

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- Fuel and purchased power costs were recovered from customers on a one-for-one basis by our Wisconsin wholesale electric operations and our Michigan retail electric operations.
- 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. 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.
- WE received payments from MISO under an SSR agreement for its PIPP units through February 1, 2015. We recorded revenue for these payments to recover costs for operating and maintaining these units. See Note 23, Regulatory Environment, for more information.
- The rates for all of our natural gas utilities included 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.
- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs.
- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.
- The rates of PGL and NSG, and the residential rates of WE and WG, included 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, NSG, MERC, and MGU included decoupling mechanisms. These mechanisms differ by state and allow utilities to recover or refund differences between actual and authorized margins. MGU's decoupling mechanism was discontinued after December 31, 2015. See Note 23, Regulatory Environment, for more information.
- PGL's rates included a cost recovery mechanism for SMP costs.

Revenues are also impacted by other accounting policies related to our electric utilities' participation in the MISO Energy Markets. Our electric utilities sell and purchase power in the MISO Energy Markets, which operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour. If our electric utilities were a net seller in a particular hour, the net amount was reported as operating revenues. If our electric utilities were a net purchaser in a particular hour, the net amount was recorded as cost of sales on our income statements.

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, WG, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed above. As a result, we did not have any significant concentrations of credit risk at December 31, 2017. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2017.

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

| <i>(in millions)</i>   | 2017            | 2016            |
|------------------------|-----------------|-----------------|
| Natural gas in storage | \$ 209.0        | \$ 223.1        |
| Materials and supplies | 211.2           | 206.5           |
| Fossil fuel            | 118.8           | 158.0           |
| <b>Total</b>           | <b>\$ 539.0</b> | <b>\$ 587.6</b> |

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 15% and

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18% of total inventories at December 31, 2017 and 2016, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2017 and 2016, exceeded the LIFO cost by \$152.1 million and \$92.9 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of \$4.68 at December 31, 2017, and \$3.63 at December 31, 2016.

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

**(f) Investments Held in Rabbi Trust**—Integrys has a rabbi trust that 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. The trust holds investments that are classified as trading securities for accounting purposes. As we do not intend to sell the investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were \$18.8 million for the year ended December 31, 2017. The net unrealized gains and losses included in earnings for the years ended December 31, 2016 and 2015 were not significant.

**(g) Regulatory Assets and Liabilities**—The economic effects of regulation can result in regulated companies recording costs and revenues that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs or revenues would be recognized by a nonregulated company. When this occurs, regulatory assets and regulatory liabilities are recorded on the balance sheet. Regulatory assets represent probable future revenues associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts that are collected in rates for future costs.

Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 4, Regulatory Assets and Liabilities, for more information.

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

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

| Annual Utility Composite Depreciation Rates | 2017  | 2016  | 2015  |
|---|-------|-------|-------|
| WE  | 2.95% | 3.00% | 3.01% |
| WPS (1)                                     | 2.55% | 2.58% | 1.30% |
| WG  | 2.30% | 2.34% | 2.36% |
| UMERC (2)                                   | 2.46% | N/A   | N/A   |
| PGL (1)                                     | 3.29% | 3.31% | 1.67% |
| NSG (1)                                     | 2.43% | 2.44% | 1.22% |
| MERC (1)                                    | 2.51% | 2.53% | 1.26% |
| MGU (1)                                     | 2.61% | 2.63% | 1.32% |

(1) The rates shown for 2015 are for a partial year as a result of the acquisition of Integrys. The full year rate would be approximately double the rate shown.

(2) UMERC became operational effective January 1, 2017. See Note 1(a), Nature of Operations, for more information.

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.

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

**(i) Allowance for Funds Used During Construction**—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC – Debt) used during plant construction, and a return on shareholders' capital (AFUDC – Equity) used for construction purposes. AFUDC – Debt is recorded as a reduction of interest expense, and AFUDC – Equity is recorded in other income, net.

The majority of AFUDC is recorded at WE, WPS, WBS, and WG. Approximately 50% of WE's, WPS's, WBS's, and WG's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while the 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 2017, 2016, or 2015. Average AFUDC rates are shown below:

|     | 2017                      |                              |
|-----|---------------------------|------------------------------|
|     | Average AFUDC Retail Rate | Average AFUDC Wholesale Rate |
| WE  | 8.45%                     | 5.94%                        |
| WPS | 7.72%                     | 1.01%                        |
| WBS | 7.72%                     | N/A                          |
| WG  | 8.33%                     | N/A                          |

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

| <i>(in millions)</i> | 2017    | 2016    | 2015    |
|----------------------|---------|---------|---------|
| AFUDC – Debt         | \$ 4.9  | \$ 10.9 | \$ 8.6  |
| AFUDC – Equity       | \$ 11.4 | \$ 25.1 | \$ 20.1 |

**(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 8, 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, and 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 applicable criteria to be considered probable of abandonment, we assess the likelihood of recovery of the remaining carrying 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 the abandoned generating unit, an impairment charge may be required. An impairment

charge would be recorded if the remaining carrying value of the abandoned generating unit is greater than the present value of the amount expected to be recovered from ratepayers. See Note 5, Property, Plant, and Equipment, for more information.

The carrying amounts of cost and 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, a 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 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 7, 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 modifies 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.

ASU 2016-09 also requires excess tax benefits to be classified as an operating activity on the statement of cash flows. As we have elected to apply this provision on a prospective basis, the prior year amounts will continue to be reflected as a financing activity. As allowed under this ASU, we have also 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 a three-year period. 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 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.

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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:

|  | 2017        | 2016        | 2015        |
|--|-------------|-------------|-------------|
| Stock options granted                                  | 552,215     | 794,764     | 516,475     |
| Estimated weighted-average fair value per stock option | \$ 7.45     | \$ 5.14     | \$ 5.29     |
| Assumptions used to value the options:                 |             |             |             |
| Risk-free interest rate                                | 0.7% – 2.5% | 0.4% – 2.2% | 0.1% – 2.1% |
| Dividend yield   | 3.5%        | 4.0%        | 3.7%        |
| Expected volatility                                    | 19.0%       | 18.1%       | 18.0%       |
| Expected life (years)                                  | 6.8         | 6.1         | 5.8         |

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 have a three-year vesting period 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 non-employee directors after January 1, 2017, fully vest on the one-year anniversary of the grant date.

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 a three-year period, and beginning in 2017, other performance metrics as determined by the Compensation Committee. Under the terms of the award, participants may earn between 0% and 175% of the performance unit award, as adjusted pursuant to the terms of the plan. Performance units granted on or after January 1, 2016 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 recorded over the three-year performance period.

See Note 9, 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. The calculation of diluted earnings per share for the years ended December 31, 2016 and 2015 excluded 181,709 and 516,475 stock options, respectively, that had an anti-dilutive effect. There were no securities that had an anti-dilutive effect for the year ended December 31, 2017.

**(n) Deferred Revenue**—As part of the construction of We Power's electric generating units, we capitalized interest during construction. As allowed under the lease agreements, we were able to collect the carrying costs during the construction of these generating units from our utility customers. The carrying costs that we collected during construction have been recorded as deferred revenue on our balance sheets and we are amortizing the deferred carrying costs to revenue over the individual lease terms.

**(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

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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. 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. See Note 13, Income Taxes, for more information.

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

**(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.

Derivatives were transferred between levels of the fair value hierarchy primarily due to observable pricing becoming available. We recognize transfers between levels of the fair value hierarchy at their value as of the end of the reporting period.

Due to the short-term nature of cash and cash equivalents, net accounts receivable and unbilled revenues, accounts payable, and short-term debt, the carrying amount of each such item approximates fair value. The fair value of our preferred stock is estimated based on the quoted market value for the same issue, or by using a dividend discount model. The fair value of our long-term debt is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of United States Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

See Note 14, 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 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. Realized gains and losses on derivative instruments are primarily recorded in cost of sales on the income statements. 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 15, Derivative Instruments, for more information.

**(r) Guarantees**— We follow the guidance of the Guarantees Topic of the FASB ASC, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. See Note 16, 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 17, 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 7, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 21, 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.

**NOTE 2—ACQUISITIONS****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 the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. The aggregate purchase price is approximately \$174 million of which WPS's proportionate share is 44.6%, or approximately \$78 million. WPS currently purchases 44.6% of the facility's energy output under a power purchase agreement. The FERC approved the transaction on January 16, 2018. The transaction remains subject to PSCW approval and is expected to close in the spring of 2018.

**Acquisition of Natural Gas Storage Facilities in Michigan**

On June 30, 2017, we completed the acquisition of Bluewater for \$226.0 million. Bluewater owns natural gas storage facilities in Michigan that will provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. In addition, we incurred \$4.9 million of acquisition related costs.

The table below shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition. The allocation is subject to change during the remainder of the measurement period, which ends one year from the acquisition date, as we obtain additional information. 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. Bluewater is regulated by the FERC. Its operations meet the criteria, and accordingly, are accounted for following the accounting guidance under the Regulated Operations Topic of the FASB ASC. See Note 19, Segment Information, for more information.

*(in millions)*

|                                     |           |              |
|-------------------------------------|-----------|--------------|
| Current assets                      | \$        | 2.0          |
| Property, plant, and equipment, net |           | 217.6        |
| Goodwill                            |           | 7.3          |
| Current liabilities                 |           | (0.9)        |
| <b>Total purchase price</b>         | <b>\$</b> | <b>226.0</b> |

**Acquisition of Integrys**

On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys and changed its name to WEC Energy Group, Inc. Integrys is a provider of regulated natural gas and electricity, as well as nonregulated renewable energy products and services. Integrys also provided CNG products and services prior to the sale of ITF in the first quarter of 2016. Integrys held a 34% interest in ATC, a for-profit transmission company regulated by the FERC, which has since been moved to another of our subsidiaries. The acquisition of Integrys has provided increased scale, operating efficiencies, and the potential for long-term cost savings through a combination of lower capital and operating costs.

### Purchase Price

Pursuant to the Merger Agreement, Integrys's shareholders received 1.128 shares of Wisconsin Energy Corporation common stock and \$18.58 in cash per share of Integrys common stock. The total consideration transferred was based on the closing price of Wisconsin Energy Corporation common stock on June 29, 2015, and was calculated as follows:

| <i>(in millions, except per share amounts)</i>                               | Consideration Paid |                   |                   |
|--|--------------------|-------------------|-------------------|
|  | Stock              | Cash              | Total             |
| Integrys common shares outstanding at June 29, 2015                          | 79,963,091         | 79,963,091        |                   |
| Exchange ratio   | 1.128              |                   |                   |
| Wisconsin Energy Corporation shares issued for Integrys shares *             | 90,187,884         |                   |                   |
| Closing price of Wisconsin Energy Corporation common shares on June 29, 2015 | \$45.16            |                   |                   |
| Fair value of common stock issued  | \$ 4,072.9         |                   | \$ 4,072.9        |
| Cash paid per share of Integrys shares outstanding                           |                    | \$18.58           |                   |
| Fair value of cash paid for Integrys shares *                                |                    | \$ 1,486.2        | \$ 1,486.2        |
| Consideration attributable to settlement of equity awards, net of tax        |                    | \$ 24.0           | \$ 24.0           |
| <b>Total purchase price</b>  | <b>\$ 4,072.9</b>  | <b>\$ 1,510.2</b> | <b>\$ 5,583.1</b> |

\* Fractional shares of 10,483 totaling \$0.5 million were paid in cash.

All Integrys unvested stock-based compensation awards became fully vested upon the close of the acquisition and were either paid to award recipients in cash, or the value of the awards was deferred into a deferred compensation plan. In addition, all vested but unexercised Integrys stock options were paid in cash. In accordance with accounting guidance for business combinations, the acceleration of the vesting was recorded as an acquisition-related expense.

### Allocation of Purchase Price

The Integrys assets acquired and liabilities assumed were measured at estimated fair value in accordance with the accounting guidance under the Business Combinations Topic in the FASB ASC. Substantially all of Integrys's operations are subject to the rate-setting authority of federal and state regulatory commissions. These operations are accounted for following the accounting guidance under the Regulated Operations Topic of the FASB ASC. The underlying assets and liabilities of ATC are also regulated by the FER. Integrys's assets and liabilities that are subject to rate-setting provisions provide revenues derived from costs, including a return on investment of assets less liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets and liabilities acquired, nor the pro forma financial information, reflect any adjustments related to these amounts.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The goodwill reflects the value paid for the increased scale and efficiencies as a result of the combination. The goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill. See Note 8, Goodwill, for the allocation of goodwill to our reportable segments.

During the first six months of 2016, adjustments were made to the estimated fair values of the assets acquired and liabilities assumed, primarily in connection with the sale of ITF and reserves recorded for likely settlements of certain legal and regulatory matters. The table below shows the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition:

| <i>(in millions)</i>                |                   |
|-------------------------------------|-------------------|
| Current assets                      | \$ 1,060.1        |
| Property, plant, and equipment, net | 7,107.4           |
| Goodwill                            | 2,604.3           |
| Other long-term assets *            | 2,830.5           |
| Current liabilities                 | (1,320.7)         |
| Long-term debt                      | (2,943.6)         |
| Other long-term liabilities         | (3,703.8)         |
| Preferred stock of subsidiary       | (51.1)            |
| <b>Total purchase price</b>         | <b>\$ 5,583.1</b> |

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\* Includes equity method goodwill related to Integrys's investment in ATC. See Note 18, Investment in Transmission Affiliates, for more information.

In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments, which requires that an acquirer recognize and disclose adjustments to provisional amounts that are identified during an acquisition measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. Early adoption was permitted for any interim and annual financial statements that had not yet been issued. We early adopted ASU 2015-16 in the fourth quarter of 2015. Adoption had no impact on our financial statements.

### Conditions of Approval

The acquisition was subject to the approvals of various government agencies, including the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. Approvals were obtained from all agencies subject to several conditions.

The PSCW order includes the following conditions:

- WE and WG are each subject to an earnings sharing mechanism for three years beginning January 1, 2016. Under the earnings sharing mechanisms, if either company earns above its authorized return, 50% of the first 50 basis points of additional utility earnings will be shared with customers. For WE, the additional utility earnings will be used to reduce the company's transmission escrow. For WG, additional utility earnings will be used to reduce the costs of its Western Gas Lateral project that would otherwise be included in rates. All utility earnings above the first 50 basis points will be used to reduce the transmission escrow for WE and reduce the costs of the Western Gas Lateral that would otherwise be included in rates for WG. For the years ended December 31, 2017 and 2016, WE and WG recorded a combined \$2.9 million and \$24.4 million of expense related to these earnings sharing mechanisms, respectively.
- Any future electric generation projects affecting Wisconsin ratepayers submitted by us or our subsidiaries will first consider the extent to which existing intercompany resources can meet energy and capacity needs. In September 2015, WPS and WE filed a joint integrated resource plan with the PSCW for their combined loads, which indicated that no new generation was needed at the time.

The ICC order included a base rate freeze for PGL and NSG effective for two years after the close of the acquisition. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or GCRMs.

### Pro Forma Information

The following unaudited pro forma financial information reflects the consolidated results and amortization of purchase price adjustments as if the acquisition had taken place on January 1, 2014. The unaudited pro forma financial information is presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or our future consolidated results.

The pro forma financial information does not reflect any potential cost savings from operating efficiencies resulting from the acquisition and does not include certain acquisition-related costs.

| <i>(in millions, except per share amounts)</i>   | Year ended December<br>31, 2015 |
|--|---------------------------------|
| <b>Unaudited pro forma financial information</b> |                                 |
| Operating revenues                               | \$ 7,727.1                      |
| Net income attributed to common shareholders     | \$ 873.5                        |
| Earnings per share (Basic)                       | \$ 2.77                         |
| Earnings per share (Diluted)                     | \$ 2.75                         |

## Impact of Acquisition

As a result of the acquisition, our ownership of ATC increased to approximately 60%. We have made commitments with respect to our voting rights of the combined ownership of ATC, which are included as enforceable conditions in the FERC and PSCW orders approving the acquisition. Under GAAP, these commitments do not allow for the consolidation of ATC in our financial statements and the 60% ownership is accounted for as an equity method investment subsequent to the close of the acquisition. See Note 18, Investment in Transmission Affiliates, for more information.

In connection with the acquisition, WEC Energy Group and its subsidiaries recorded pre-tax acquisition costs of \$3.5 million and \$107.6 million during 2016 and 2015, respectively. These costs consisted of employee-related expenses, professional fees, and other miscellaneous costs. They are primarily recorded in the other operation and maintenance line item on the income statements.

Included in the 2015 acquisition costs was \$24.9 million of severance expense that resulted from employee reductions related to the post-acquisition integration. Severance expense incurred after 2015 was not significant. The 2015 severance expense was recorded in the following segments:

| <i>(in millions)</i>           | <b>Year ended December 31,<br/>2015</b> |
|--------------------------------|---|
| Wisconsin                      | \$ 11.1                                 |
| Illinois                       | 0.9                                     |
| Other states                   | 0.1                                     |
| Corporate and other            | 12.8                                    |
| <b>Total severance expense</b> | <b>\$ 24.9</b>                          |

Severance payments made during 2017 were not significant. Severance payments of \$7.5 million and \$16.9 million were made during 2016 and 2015, respectively. The severance accrual on our balance sheets at December 31, 2017 and 2016 related to the acquisition of Integrys was not significant.

Our revenues for the year ended December 31, 2015 include revenues attributable to Integrys of \$1,416.8 million. Included in our net income for the year ended December 31, 2015, is net income attributable to Integrys of \$65.9 million.

## NOTE 3—DISPOSITIONS

### Wisconsin Segment

#### *Sale of Milwaukee County Power Plant*

In April 2016, we sold the MCPP steam generation and distribution assets, located in Wauwatosa, Wisconsin. MCPP primarily provided steam to the Milwaukee Regional Medical Center hospitals and other campus buildings. During the second quarter of 2016, we recorded a pre-tax gain on the sale of \$10.9 million (\$6.5 million after tax), which was included in other operation and maintenance on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations of this plant 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.

### Corporate and Other Segment

#### *Sale of Bostco 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. 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.

### Sale of Certain Assets of Wisvest

In April 2016, as part of the MCPP sale transaction, we sold the chilled water generation and distribution assets of Wisvest, which are used to provide chilled water services to the Milwaukee Regional Medical Center hospitals and other campus buildings. During the second quarter of 2016, we recorded a pre-tax gain on the sale of \$19.6 million (\$11.8 million after tax), 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.

### Sale of Integrys Transportation Fuels

Through a series of transactions in the fourth quarter of 2015 and the first quarter of 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. There was no gain or loss recorded on the sales, as ITF's assets and liabilities were adjusted to fair value through purchase accounting. The results of operations of ITF remained in continuing operations through the sale date as the sale of ITF did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. The pre-tax profit or loss of this component was not material through the sale date in 2016.

### NOTE 4—REGULATORY ASSETS AND LIABILITIES

We recorded a \$2,450 million change in our deferred taxes for our regulated utilities due to the enactment of the Tax Legislation, which resulted in both an increase to income tax related regulatory liabilities as well as a decrease to certain existing income tax related regulatory assets represented in Income tax related items in the table below. The \$2,450 million change in our deferred taxes represents our estimate of the tax benefit that will be returned to ratepayers through future refunds, bill credits, riders, or reductions in other regulatory assets. See Note 13, Income Taxes, for more information on the Tax Legislation.

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

| <i>(in millions)</i>                    | 2017              | 2016              | See Note |
|---|-------------------|-------------------|----------|
| <b>Regulatory assets (1) (2)</b>        |                   |                   |          |
| Unrecognized pension and OPEB costs (3) | \$ 1,142.0        | \$ 1,252.1        | 17       |
| Environmental remediation costs (4)     | 676.6             | 702.7             | 21       |
| SSR                                     | 298.9             | 188.1             | 23       |
| Electric transmission costs             | 221.0             | 234.1             | 23       |
| AROs                                    | 192.2             | 179.2             | 7        |
| We Power generation (5)                 | 71.3              | 54.1              |          |
| Uncollectible expense (6)               | 35.1              | 25.6              | 1(d)     |
| Energy efficiency programs (7)          | 24.6              | 36.7              |          |
| Income tax related items                | 15.7              | 285.1             | 13       |
| Other, net                              | 163.0             | 180.6             |          |
| <b>Total regulatory assets</b>          | <b>\$ 2,840.4</b> | <b>\$ 3,138.3</b> |          |
| <b>Balance Sheet Presentation</b>       |                   |                   |          |
| Current assets (8)                      | \$ 37.2           | \$ 50.4           |          |
| Regulatory assets                       | 2,803.2           | 3,087.9           |          |
| <b>Total regulatory assets</b>          | <b>\$ 2,840.4</b> | <b>\$ 3,138.3</b> |          |

(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 the table.

(2) As of December 31, 2017, we had \$116.9 million of regulatory assets not earning a return and \$261.1 million of regulatory assets earning a return based on short-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 certain unrecognized pension and OPEB costs, unmortgaged loss on reacquired debt, and plant-related costs. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

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- (3) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We are authorized recovery of this regulatory asset over the average remaining service life of each plan.
- (4) As of December 31, 2017, we had not yet made cash expenditures for \$617.4 million of these environmental remediation costs.
- (5) Represents amounts recoverable from customers related to WE's costs of the generating units leased from We Power, including subsequent capital additions.
- (6) 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.
- (7) Represents amounts recoverable from customers related to programs at the utilities designed to meet energy efficiency standards.
- (8) Short-term regulatory assets are recorded in accounts receivable and unbilled revenues on our balance sheets.

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

| <i>(in millions)</i>                                 | 2017              | 2016              | See Note |
|--|-------------------|-------------------|----------|
| <b>Regulatory liabilities</b>                        |                   |                   |          |
| 2017 Tax Legislation impact and income tax related   | \$ 2,134.1        | \$ —              | 13       |
| Removal costs (1)                                    | 1,294.9           | 1,262.7           |          |
| Unrecognized pension and OPEB costs (2)              | 114.2             | 63.0              | 17       |
| Mines deferral (3)                                   | 95.1              | 70.2              |          |
| Energy costs refundable through rate adjustments (4) | 42.0              | 88.7              |          |
| Uncollectible expense (5)                            | 24.7              | 36.1              | 1(d)     |
| Derivatives  | 11.0              | 41.1              | 1(q)     |
| Other, net   | 44.4              | 35.4              |          |
| <b>Total regulatory liabilities</b>                  | <b>\$ 3,760.4</b> | <b>\$ 1,597.2</b> |          |
| <b>Balance Sheet Presentation</b>                    |                   |                   |          |
| Current liabilities                                  | \$ 41.8           | \$ 33.4           |          |
| Regulatory liabilities                               | 3,718.6           | 1,563.8           |          |
| <b>Total regulatory liabilities</b>                  | <b>\$ 3,760.4</b> | <b>\$ 1,597.2</b> |          |

- (1) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.
- (2) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We will amortize this regulatory liability into net periodic benefit cost over the average remaining service life of each plan.
- (3) Represents the deferral of revenues less the associated cost of sales related to sales to the mines, which were not included in the 2015 rate order. We intend to request that this deferral be applied for the benefit of Wisconsin retail electric customers in a future rate proceeding.
- (4) Represents energy costs that will be refunded to customers in the future.
- (5) 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.

**NOTE 5—PROPERTY, PLANT, AND EQUIPMENT**

Property, plant, and equipment consisted of the following utility and non-utility and other assets at December 31:

| <i>(in millions)</i>                                     | 2017               | 2016               |
|--|--------------------|--------------------|
| Utility property, plant, and equipment                   | \$ 23,646.7        | \$ 24,185.1        |
| Less: Accumulated depreciation                           | 7,021.8            | 7,609.7            |
| Net  | 16,624.9           | 16,575.4           |
| CWIP   | 508.2              | 320.0              |
| Plant to be retired, net                                 | 930.6              | —                  |
| Net utility property, plant, and equipment               | 18,063.7           | 16,895.4           |
| Non-utility and other property, plant, and equipment     | 3,797.2            | 3,520.3            |
| Less: Accumulated depreciation                           | 671.3              | 604.9              |
| Net  | 3,125.9            | 2,915.4            |
| CWIP   | 157.4              | 104.7              |
| Net non-utility and other property, plant, and equipment | 3,283.3            | 3,020.1            |
| <b>Total property, plant, and equipment</b>              | <b>\$ 21,347.0</b> | <b>\$ 19,915.5</b> |

**Wisconsin Segment Plant to be Retired**

We have evaluated future plans for our older and less efficient fossil fuel generating units and have announced the retirement of the plants identified below. The net book value of these plants was classified as plant to be retired within property, plant, and equipment on our balance sheet at December 31, 2017. In addition, severance expense in the amount of \$29.4 million was recorded within the Wisconsin segment in 2017 related to these announced plant retirements.

***Pleasant Prairie Power Plant***

As a result of a MISO ruling in December 2017, Pleasant Prairie must be shut down no later than April 10, 2018. Because we had an obligation at December 31, 2017 to shut down the Pleasant Prairie plant in April 2018, retirement of the plant was probable at December 31, 2017. The net book value of this generating unit was \$681.3 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is included in rate base, and WE continues to depreciate it on a straight-line basis using the composite depreciation rates approved by the PSCW. The physical dismantlement of the plant will not occur immediately. It may take several years to finalize long-term plans for the site. See Note 21, Commitments and Contingencies, for more information.

***Presque Isle Power Plant***

In October 2017, the MPSC approved UMERC’s application to construct and operate approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. Upon receiving this approval, retirement of the PIPP generating units became probable. The new units are expected to begin commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. The net book value of these units was \$191.4 million at December 31, 2017. These units are included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. The net book value of these assets was transferred from plant in service to plant to be retired. See Note 23, Regulatory Environment, for more information regarding the new natural gas-fired generation.

***Pulliam Power Plant***

As a result of MISO’s ruling that WPS will be able retire the Pulliam generating units when certain transmission lines are completed, expected near the end of 2018, retirement of the Pulliam generating units was probable at December 31, 2017. The net book value of these generating units was \$44.9 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 21, Commitments and Contingencies, for more information.

## Edgewater Unit 4

As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, retirement of the Edgewater 4 generating unit was probable at December 31, 2017. WPS anticipates that the plant will be retired by September 30, 2018. The net book value of WPS's ownership share of this generating unit was \$13.0 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is included in rate base, and WPS continues to depreciate it on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 21, Commitments and Contingencies, for more information regarding the Consent Decree.

### NOTE 6—JOINTLY OWNED 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 facilities at December 31, 2017 was as follows:

| <i>(in millions, except for percentages and MW)</i> | We Power                                  |               | WPS   |                                 |  |
|---|---|---------------|---|---------------------------------|--|
|   | Elm Road Generating Station Units 1 and 2 | Weston Unit 4 | Columbia Energy Center Units 1 and 2 <sup>(2)</sup> | Edgewater Unit 4 <sup>(3)</sup> |  |
| Ownership   | 83.34%                                    | 70.0%         | 29.5%   | 31.8%                           |  |
| Share of rated capacity (MW) <sup>(1)</sup>         | 1,056.8                                   | 383.9         | 319.7   | 98.0                            |  |
| In-service date                                     | 2010 and 2011                             | 2008          | 1975 and 1978                                       | 1969                            |  |
| Property, plant, and equipment                      | \$ 2,431.0                                | \$ 600.5      | \$ 412.7  | \$ 45.9                         |  |
| Accumulated depreciation                            | \$ (351.2)                                | \$ (189.2)    | \$ (127.3)  | \$ (32.9)                       |  |
| CWIP  | \$ 9.5                                    | \$ 5.3        | \$ 27.6   | \$ —                            |  |

(1) Based on expected capacity ratings for summer 2018. 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 (Columbia) is jointly owned by Wisconsin Power and Light (WPL), Madison Gas and Electric (MGE), and WPS. In October 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement between the parties allowing WPS and MGE to forgo certain capital expenditures at Columbia. As a result, WPL will incur these capital expenditures in exchange for a proportional increase in its ownership share of Columbia. Based upon the additional capital expenditures WPL expects to incur through June 1, 2020, WPS's ownership interest would decrease to 27.5%.

(3) WPS anticipates that the Edgewater Unit 4 generating unit will be retired by September 30, 2018. See Note 5, Property, Plant, and Equipment, for more information.

### NOTE 7—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]); asbestos abatement at certain generation and substation facilities, office buildings, and service centers; the removal and dismantlement of 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 by PDL for the removal of solar equipment components. On our balance sheets, AROs are recorded within other long-term liabilities.

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The following table shows changes to our AROs during the years ended December 31:

| <i>(in millions)</i>                            | 2017      |                     | 2016      |              | 2015      |                     |
|---|-----------|---------------------|-----------|--------------|-----------|---------------------|
| Balance as of January 1                         | \$        | 557.7               | \$        | 571.2        | \$        | 43.6                |
| Integrus subsidiaries                           |           | —                   |           | —            |           | 491.0               |
| Accretion                                       |           | 27.5                |           | 28.3         |           | 14.5                |
| Additions and revisions to estimated cash flows |           | 26.5 <sup>(1)</sup> |           | —            |           | 35.5 <sup>(2)</sup> |
| Liabilities settled                             |           | (38.0)              |           | (41.8)       |           | (13.4)              |
| <b>Balance as of December 31</b>                | <b>\$</b> | <b>573.7</b>        | <b>\$</b> | <b>557.7</b> | <b>\$</b> | <b>571.2</b>        |

(1) AROs increased \$20.5 million in 2017 due to revisions made to estimated cash flows primarily for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG. In addition, an ARO of \$5.5 million was recorded related to the removal and dismantlement of WE's Rothschild Biomass Plant.

(2) During 2015, an ARO of \$16.1 million was recorded for fly-ash landfills located at generation facilities owned by WE and WPS. An ARO of \$9.0 million was also recorded during 2015 for the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities rule passed by the EPA in April 2015. In addition, AROs increased \$10.4 million in 2015 due to revisions made to estimated cash flows primarily for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG.

## NOTE 8—GOODWILL

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows changes to our goodwill balances by segment during the years ended December 31, 2017 and 2016:

| <i>(in millions)</i>                                     | Wisconsin         |                   | Illinois        |                 | Other States    |                 | Non-Utility Energy Infrastructure |             | Total             |                   |
|--|-------------------|-------------------|-----------------|-----------------|-----------------|-----------------|-----------------------------------|-------------|-------------------|-------------------|
|  | 2017              | 2016              | 2017            | 2016            | 2017            | 2016            | 2017                              | 2016        | 2017              | 2016              |
| Goodwill balance as of January 1                         | \$ 2,104.3        | \$ 2,109.5        | \$ 758.7        | \$ 731.2        | \$ 183.2        | \$ 182.8        | \$ —                              | \$ —        | \$ 3,046.2        | \$ 3,023.5        |
| Adjustment to Integrus purchase price allocation         | —                 | (5.2)             | —               | 27.5            | —               | 0.4             | —                                 | —           | —                 | 22.7              |
| Acquisition of Bluewater <sup>(1)</sup>                  | —                 | —                 | —               | —               | —               | —               | 7.3                               | —           | 7.3               | —                 |
| <b>Goodwill balance as of December 31 <sup>(2)</sup></b> | <b>\$ 2,104.3</b> | <b>\$ 2,104.3</b> | <b>\$ 758.7</b> | <b>\$ 758.7</b> | <b>\$ 183.2</b> | <b>\$ 183.2</b> | <b>\$ 7.3</b>                     | <b>\$ —</b> | <b>\$ 3,053.5</b> | <b>\$ 3,046.2</b> |

(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, 2017.

In the third quarter of 2017, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments resulted from these tests.

## NOTE 9—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:

| <i>(in millions)</i>             | 2017 |      | 2016 |      | 2015 |      |
|----------------------------------|------|------|------|------|------|------|
| Stock options                    | \$   | 3.4  | \$   | 3.5  | \$   | 3.3  |
| Restricted stock                 |      | 5.4  |      | 5.8  |      | 7.0  |
| Performance units                |      | 20.2 |      | 8.7  |      | 13.0 |
| Stock-based compensation expense | \$   | 29.0 | \$   | 18.0 | \$   | 23.3 |
| Related tax benefit              | \$   | 11.6 | \$   | 7.2  | \$   | 9.3  |

Stock-based compensation costs capitalized during 2017, 2016, and 2015 were not significant.

## Stock Options

The following is a summary of our stock option activity during 2017:

| 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, 2017          | 5,122,775         | \$ 38.95                        |  |   |
| Granted                                    | 552,215           | \$ 58.31                        |  |   |
| Exercised                                  | (1,019,111)       | \$ 30.24                        |  |   |
| Forfeited                                  | (11,665)          | \$ 56.48                        |  |   |
| <b>Outstanding as of December 31, 2017</b> | <b>4,644,214</b>  | <b>\$ 43.11</b>                 | <b>6.0</b>   | <b>\$ 108.3</b>                         |
| <b>Exercisable as of December 31, 2017</b> | <b>3,275,850</b>  | <b>\$ 38.23</b>                 | <b>5.0</b>   | <b>\$ 92.4</b>                          |

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, 2017. This is calculated as the difference between our closing stock price on December 31, 2017, 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, 2017, 2016, and 2015 was \$33.8 million, \$55.4 million, and \$36.1 million, respectively. The actual tax benefit from option exercises for the same periods was approximately \$13.5 million, \$22.2 million, and \$14.5 million, respectively.

As of December 31, 2017, approximately \$2.7 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 660,655 non-qualified stock options with a weighted-average exercise price of \$66.02 and a weighted-average grant date fair value of \$7.84 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 2017:

| Restricted Shares                          | Number of Shares | Weighted-Average Grant Date Fair Value |
|--|------------------|--|
| Outstanding as of January 1, 2017          | 220,046          | \$ 51.30                               |
| Granted                                    | 82,622           | \$ 58.10                               |
| Released                                   | (91,147)         | \$ 48.98                               |
| Forfeited                                  | (7,033)          | \$ 55.60                               |
| <b>Outstanding as of December 31, 2017</b> | <b>204,488</b>   | <b>\$ 54.94</b>                        |

The intrinsic value of restricted stock released was \$5.4 million, \$7.7 million, and \$3.7 million for the years ended December 31, 2017, 2016, and 2015, respectively. The actual tax benefit from released restricted shares for the same years was \$2.1 million, \$3.1 million, and \$1.3 million, respectively.

As of December 31, 2017, approximately \$4.1 million of unrecognized compensation cost related to restricted stock was expected to be recognized over the next 1.5 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 131,731 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 \$64.97 per share.

## Performance Units

During 2017, 2016, and 2015, the Compensation Committee awarded 237,650; 297,305; and 195,365 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

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Performance units with an intrinsic value of \$6.7 million, \$19.1 million, and \$13.2 million were settled during 2017, 2016, and 2015, respectively. The actual tax benefit from the distribution of performance units for the same years was \$2.1 million, \$6.8 million, and \$4.8 million, respectively.

At December 31, 2017, we had 563,033 performance units outstanding, including dividend equivalents. A liability of \$27.6 million was recorded on our balance sheet at December 31, 2017 related to these outstanding units. As of December 31, 2017, approximately \$23.5 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.4 years on a weighted-average basis.

During the first quarter of 2018, we settled performance units with an intrinsic value of \$7.8 million. The actual tax benefit from the distribution of these awards was \$1.7 million. In January 2018, the Compensation Committee also awarded 217,560 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 and our non-utility subsidiary, We Power. 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 U MERC and MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with their most recent rate orders, WE, WG, and WPS 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 levels of 51%, 49.5%, and 51%, respectively. 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 levels.

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.

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

As of December 31, 2017, restricted net assets of our consolidated subsidiaries totaled approximately \$6.3 billion. Our equity in undistributed earnings of investees accounted for by the equity method were approximately \$355 million. The total of these amounts exceeds 25% of our consolidated net assets as of December 31, 2017.

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 2017, 2016, or 2015, other than for the Integrys acquisition in 2015. See Note 2, Acquisitions, for more information.

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The following is a summary of shares purchased to fulfill exercised stock options and restricted stock awards during the years ended December 31:

| <i>(in millions)</i>     | 2017    | 2016     | 2015    |
|--------------------------|---------|----------|---------|
| Shares purchased         | 1.1     | 1.8      | 1.5     |
| Cost of shares purchased | \$ 71.3 | \$ 108.0 | \$ 74.7 |

### Common Stock Dividends

During the year ended December 31, 2017, our Board of Directors declared common stock dividends which are summarized below:

| Date Declared    | Date Payable      | Per Share | Period         |
|------------------|-------------------|-----------|----------------|
| January 19, 2017 | March 1, 2017     | \$0.52    | First quarter  |
| April 20, 2017   | June 1, 2017      | \$0.52    | Second quarter |
| July 20, 2017    | September 1, 2017 | \$0.52    | Third quarter  |
| October 19, 2017 | December 1, 2017  | \$0.52    | Fourth quarter |

On January 18, 2018, our Board of Directors declared a quarterly cash dividend of \$0.5525 per share, which equates to an annual dividend of \$2.21 per share. The dividend is payable on March 1, 2018, to shareholders of record on February 14, 2018. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

### NOTE 10—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2017 and 2016:

| <i>(in millions, except share and per share amounts)</i> | Shares Authorized | Shares Outstanding | Redemption Price Per Share | Total   |
|--|-------------------|--------------------|----------------------------|---------|
| <b>WEC Energy Group</b>                                  |                   |                    |                            |         |
| \$.01 par value Preferred Stock                          | 15,000,000        | —                  | —                          | \$ —    |
| <b>WE</b>  |                   |                    |                            |         |
| \$100 par value, Six Per Cent. Preferred Stock           | 45,000            | 44,498             | —                          | 4.4     |
| \$100 par value, Serial Preferred Stock                  | 2,286,500         | —                  | —                          | —       |
| 3.60% Series   | —                 | 260,000            | \$ 101                     | 26.0    |
| \$25 par value, Serial Preferred Stock                   | 5,000,000         | —                  | —                          | —       |
| <b>WPS</b>   |                   |                    |                            |         |
| \$100 par value, Preferred Stock                         | 1,000,000         | —                  | —                          | —       |
| <b>PGL</b>   |                   |                    |                            |         |
| \$100 par value, Cumulative Preferred Stock              | 430,000           | —                  | —                          | —       |
| <b>NSG</b>   |                   |                    |                            |         |
| \$100 par value, Cumulative Preferred Stock              | 160,000           | —                  | —                          | —       |
| <b>Total</b>   |                   |                    |                            | \$ 30.4 |

### NOTE 11—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:

| <i>(in millions, except percentages)</i>                    | 2017       | 2016     |
|---|------------|----------|
| Commercial paper  |            |          |
| Amount outstanding at December 31                           | \$ 1,444.6 | \$ 860.2 |
| Average interest rate on amounts outstanding at December 31 | 1.77%      | 0.96%    |

Our average amount of commercial paper borrowings based on daily outstanding balances during 2017, was \$833.8 million with a weighted-average interest rate during the period of 1.34%.

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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 minimum total funded debt to capitalization ratio of less than 70.0%, 65.0%, 65.0%, 65.0%, and 65.0%, respectively. As of December 31, 2017, all companies were in compliance with their respective ratio.

As of December 31, 2017, we had \$1,347.5 million of available capacity under our bank back-up credit facilities and \$1,444.6 million of commercial paper outstanding that was supported by the credit facilities.

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:

| <i>(in millions)</i>                                | Maturity      | 2017              |
|---|---------------|-------------------|
| WEC Energy Group                                    | October 2022  | \$ 1,200.0        |
| WE  | October 2022  | 500.0             |
| WPS *   | December 2020 | 400.0             |
| WG  | October 2022  | 350.0             |
| PGL   | October 2022  | 350.0             |
| <b>Total short-term credit capacity</b>             |               | <b>\$ 2,800.0</b> |
| Less:   |               |                   |
| Letters of credit issued inside credit facilities   |               | \$ 7.9            |
| Commercial paper outstanding                        |               | 1,444.6           |
| <b>Available capacity under existing agreements</b> |               | <b>\$ 1,347.5</b> |

\* In February 2018, WPS received approval from the PSCW to extend the maturity of its facility to October 2022.

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

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 12—LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

See our statements of capitalization for details on our long-term debt.

### WEC Energy Group, Inc.

Effective May 2017, the \$500.0 million of 2007 Junior Notes bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 211.25 basis points, and reset quarterly.

### Wisconsin Public Service Corporation

In November 2017, WPS's \$125.0 million of 5.65% Senior Notes matured, and the outstanding principal was repaid with proceeds WPS received from selling commercial paper.

### Minnesota Energy Resources Corporation

In June 2017, MERC issued \$120.0 million of senior notes. The senior notes were issued in three tranches: \$40.0 million of 3.11% Senior Notes due July 15, 2027; \$40.0 million of 3.41% Senior Notes due July 15, 2032; and \$40.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MERC's \$78.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from Integrys.

## Michigan Gas Utilities Corporation

In June 2017, MGU issued \$90.0 million of senior notes. The senior notes were issued in three tranches: \$30.0 million of 3.11% Senior Notes due July 15, 2027; \$30.0 million of 3.41% Senior Notes due July 15, 2032; and \$30.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MGU's \$71.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from Integrys.

## The Peoples Gas Light and Coke Company

In November 2017, PGL issued \$100.0 million of 3.77% Series EEE Bonds due December 1, 2047. The net proceeds were used for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

## Bluewater Gas Storage, LLC

In December 2017, Bluewater Gas Storage, LLC, (BGS), a subsidiary of Bluewater, issued \$125.0 million of 3.76% Senior Notes due December 20, 2047. The net proceeds were used to redeem all intercompany debt from WEC Energy Group and for other limited liability company purposes. BGS's long-term debt amortizes on a mortgage-style basis.

During 2018, \$2.3 million of BGS's outstanding \$125.0 million of 3.76% senior notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

## W.E. Power, LLC

All of We Power's outstanding long-term debt amortizes on a mortgage-style basis.

During 2018, \$5.9 million of We Power's outstanding \$101.0 million of 4.91% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, \$4.9 million of We Power's outstanding \$121.5 million of 6.00% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, \$11.4 million of We Power's outstanding \$194.1 million of 5.209% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

During 2018, \$8.9 million of We Power's outstanding \$162.4 million of 4.673% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2017.

## Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under capital leases) as of December 31, 2017:

| <i>(in millions)</i> | Payments          |
|----------------------|-------------------|
| 2018                 | \$ 838.4          |
| 2019                 | 360.1             |
| 2020                 | 686.9             |
| 2021                 | 338.8             |
| 2022                 | 40.7              |
| Thereafter           | 7,336.0           |
| <b>Total</b>         | <b>\$ 9,600.9</b> |

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

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As of December 31, 2017, WE was the obligor under a series of tax-exempt pollution control refunding bonds with an outstanding principal amount of \$80.0 million. In August 2009, WE terminated a letter of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. WE purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2017, the repurchased bonds were still outstanding, but were not reported in our long-term debt since they were held by WE. Depending on market conditions and other factors, WE may change the method used to determine the interest rate on this bond series and have it remarketed to third parties. A related bond series that had an outstanding principal amount of \$67.0 million matured on August 1, 2016.

In connection with our outstanding 2007 Junior Notes, we executed a Replacement Capital Covenant dated May 11, 2007 (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.

In connection with Integrys's outstanding 2006 Junior Notes, Integrys executed a Replacement Capital Covenant dated December 1, 2006, as replaced by a new Replacement Capital Covenant on December 1, 2010 (Integrys RCC) for the benefit of persons that buy, hold, or sell a specified series of its long-term indebtedness (covered debt). Integrys's 4.17% Senior Notes due November 1, 2020, have been designated as the covered debt under the Integrys RCC. The Integrys RCC provides that Integrys may not redeem, defease, or purchase, and that its subsidiaries may not purchase, any 2006 Junior Notes on or before December 1, 2036, unless, subject to certain limitations described in the Integrys RCC, Integrys has received a specified amount of proceeds from the sale of qualifying securities.

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.

Certain long-term debt obligations contain financial and other covenants. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

### Obligations Under Capital Leases

In 1997, WE entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. When the contract expires in 2022, WE may, at its option and with proper notice, renew for another 10 years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as cost of sales on our income statements. We paid a total of \$7.2 million and \$37.6 million in lease payments during 2017 and 2016, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting 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 approximately \$78.5 million during 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 capital lease was \$27.0 million as of December 31, 2017, and will decrease to zero over the remaining life of the contract.

The following is a summary of our capitalized leased facilities as of December 31:

| <i>(in millions)</i>                | 2017           | 2016           |
|-------------------------------------|----------------|----------------|
| Long-term power purchase commitment | \$ 140.3       | \$ 140.3       |
| Accumulated amortization            | (115.2)        | (109.5)        |
| <b>Total leased facilities</b>      | <b>\$ 25.1</b> | <b>\$ 30.8</b> |

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2017 are as follows:

| <i>(in millions)</i>                             | Payments       |
|--|----------------|
| 2018   | \$ 14.7        |
| 2019   | 15.5           |
| 2020   | 16.4           |
| 2021   | 17.2           |
| 2022   | 7.6            |
| Thereafter                                       | —              |
| Total minimum lease payments                     | 71.4           |
| Less: Estimated executory costs                  | (33.1)         |
| Net minimum lease payments                       | 38.3           |
| Less: Interest                                   | (11.3)         |
| Present value of net minimum lease payments      | 27.0           |
| Less: Due currently                              | (3.7)          |
| <b>Long-term obligations under capital lease</b> | <b>\$ 23.3</b> |

## NOTE 13—INCOME TAXES

### Income Tax Expense

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

| <i>(in millions)</i>            | 2017            | 2016            | 2015            |
|---------------------------------|-----------------|-----------------|-----------------|
| Current tax expense             | \$ 111.8        | \$ 72.7         | \$ 15.1         |
| Deferred income taxes, net      | 274.4           | 498.7           | 420.4           |
| Investment tax credit, net      | (2.7)           | (4.9)           | (1.7)           |
| <b>Total income tax expense</b> | <b>\$ 383.5</b> | <b>\$ 566.5</b> | <b>\$ 433.8</b> |

### 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:

| <i>(in millions)</i>                          | 2017            |                    | 2016            |                    | 2015            |                    |
|---|-----------------|--------------------|-----------------|--------------------|-----------------|--------------------|
|   | Amount          | Effective Tax Rate | Amount          | Effective Tax Rate | Amount          | Effective Tax Rate |
| Expected tax at statutory federal tax rates   | \$ 555.5        | 35.0 %             | \$ 526.4        | 35.0 %             | \$ 375.5        | 35.0 %             |
| State income taxes net of federal tax benefit | 100.8           | 6.4 %              | 72.8            | 4.8 %              | 73.1            | 6.8 %              |
| Federal tax reform                            | (226.9)         | (14.3)%            | —               | — %                | —               | — %                |
| Production tax credits                        | (16.8)          | (1.1)%             | (15.7)          | (1.1)%             | (17.4)          | (1.6)%             |
| AFUDC – Equity                                | (4.0)           | (0.3)%             | (8.8)           | (0.6)%             | (7.1)           | (0.7)%             |
| Investment tax credit restored                | (2.7)           | (0.2)%             | (4.9)           | (0.3)%             | (1.7)           | (0.2)%             |
| Other, net                                    | (22.4)          | (1.4)%             | (3.3)           | (0.2)%             | 11.4            | 1.1 %              |
| <b>Total income tax expense</b>               | <b>\$ 383.5</b> | <b>24.1 %</b>      | <b>\$ 566.5</b> | <b>37.6 %</b>      | <b>\$ 433.8</b> | <b>40.4 %</b>      |

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 reduces the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. We estimated a preliminary tax benefit related to the re-measurement of our deferred taxes in the amount of approximately \$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 federal Tax Legislation primarily at our non-utility energy infrastructure and corporate and

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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 is primarily due to a re-measurement of deferred tax assets and liabilities. Our revaluation of our deferred tax assets and liabilities is subject to further clarification of the new law that cannot be estimated at this time. The impact of the Tax Legislation could materially differ from this estimate due to, among other things, changes in interpretations and assumptions we have made.

On December 22, 2017, the SEC staff issued guidance in Staff Accounting Bulletin 118 (SAB 118), Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provides 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 are to be considered "provisional" as discussed in SAB 118 and subject to revision. We are awaiting additional guidance from industry and income tax authorities in order to finalize our accounting.

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

| <i>(in millions)</i>                  | 2017              | 2016              |
|---------------------------------------|-------------------|-------------------|
| <b>Deferred tax assets</b>            |                   |                   |
| Tax gross up – regulatory items       | \$ 585.8          | \$ —              |
| Future tax benefits                   | 303.9             | 430.4             |
| Employee benefits and compensation    | 164.2             | 222.0             |
| Deferred revenues                     | 128.8             | 207.2             |
| Property-related                      | 24.4              | 54.5              |
| Other                                 | 185.0             | 230.6             |
| <b>Total deferred tax assets</b>      | <b>1,392.1</b>    | <b>1,144.7</b>    |
| Valuation allowance                   | (15.7)            | (15.0)            |
| <b>Net deferred tax assets</b>        | <b>\$ 1,376.4</b> | <b>\$ 1,129.7</b> |
| <b>Deferred tax liabilities</b>       |                   |                   |
| Property-related                      | \$ 3,464.6        | \$ 4,979.3        |
| Investment in transmission affiliate  | 321.2             | 476.9             |
| Employee benefits and compensation    | 285.8             | 401.6             |
| Deferred transmission costs           | 60.1              | 93.1              |
| Other                                 | 244.5             | 325.4             |
| <b>Total deferred tax liabilities</b> | <b>4,376.2</b>    | <b>6,276.3</b>    |
| <b>Deferred tax liability, net</b>    | <b>\$ 2,999.8</b> | <b>\$ 5,146.6</b> |

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, 2017 and 2016 are summarized in the tables below:

| <b>2017</b><br><i>(in millions)</i>                | Gross Value     | Deferred Tax Effect | Valuation Allowance | Earliest Year of Expiration |
|--|-----------------|---------------------|---------------------|-----------------------------|
| <b>Future tax benefits as of December 31, 2017</b> |                 |                     |                     |                             |
| Federal foreign tax credit                         | \$ —            | \$ 13.5             | \$ (13.5)           | 2018                        |
| Other federal tax credit                           | —               | 259.6               | (0.1)               | 2025                        |
| Charitable contribution and capital loss           | 21.7            | 8.6                 | (2.1)               | 2017                        |
| State net operating loss                           | 282.7           | 17.2                | —                   | 2025                        |
| State tax credit                                   | —               | 5.0                 | —                   | 2017                        |
| <b>Balance as of December 31, 2017</b>             | <b>\$ 304.4</b> | <b>\$ 303.9</b>     | <b>\$ (15.7)</b>    |                             |

| 2016<br>(in millions)                       | Gross Value     | Deferred Tax Effect | Valuation Allowance | Earliest Year of Expiration |
|---|-----------------|---------------------|---------------------|-----------------------------|
| Future tax benefits as of December 31, 2016 |                 |                     |                     |                             |
| Federal net operating loss                  | \$ 407.6        | \$ 142.7            | \$ —                | 2031                        |
| Federal foreign tax credit                  | —               | 13.5                | (13.5)              | 2017                        |
| Other federal tax credit                    | —               | 241.1               | —                   | 2025                        |
| Charitable contribution                     | 9.4             | 4.0                 | (1.5)               | 2016                        |
| State net operating loss                    | 482.6           | 24.3                | —                   | 2024                        |
| State tax credit                            | —               | 4.8                 | —                   | 2016                        |
| <b>Balance as of December 31, 2016</b>      | <b>\$ 899.6</b> | <b>\$ 430.4</b>     | <b>\$ (15.0)</b>    |                             |

Valuation allowances of \$15.7 million have been established for certain tax benefit carryforwards obtained in the Integrys acquisition based on our projected ability to realize such benefits by offsetting future tax liabilities. This is primarily the result of bonus depreciation. Realization is dependent on generating sufficient tax liabilities prior to expiration of the tax benefit carryforwards.

### Unrecognized Tax Benefits

We previously adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

| (in millions)  | 2017           | 2016           |
|--|----------------|----------------|
| Balance as of January 1                                      | \$ 14.5        | \$ 9.5         |
| Additions for tax positions of prior years                   | 7.9            | 6.7            |
| Additions based on tax positions related to the current year | 0.5            | 1.1            |
| Reductions for tax positions of prior years                  | (5.6)          | (1.0)          |
| Reductions due to statute of limitations                     | —              | (1.8)          |
| <b>Balance as of December 31</b>                             | <b>\$ 17.3</b> | <b>\$ 14.5</b> |

The amount of unrecognized tax benefits as of December 31, 2017 and 2016, excludes deferred tax assets related to uncertainty in income taxes of \$2.1 million and \$6.6 million, respectively. As of December 31, 2017 and 2016, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was \$15.2 million and \$7.9 million, respectively.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2017, 2016, and 2015, we recognized \$0.6 million of interest income, \$0.2 million of interest expense, and zero interest, respectively, in our income statements. For the years ended December 31, 2017, 2016, and 2015, we recognized no penalties in our income statements. For the year ended December 31, 2017, we had \$0.2 million of interest accrued and no penalties accrued on our balance sheets. For the year ended December 31, 2016, we had \$0.8 million of interest accrued and no penalties accrued on our balance sheets.

We do not anticipate any significant increases or decreases 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, 2017, we were subject to examination by state or local tax authorities for the 2013 through 2017 tax years in our major state operating jurisdictions as follows:

| Jurisdiction | Years     |
|--------------|-----------|
| Federal      | 2014–2017 |
| Illinois     | 2013–2017 |
| Michigan     | 2013–2017 |
| Minnesota    | 2014–2017 |
| Wisconsin    | 2013–2017 |

**NOTE 14—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:

| <i>(in millions)</i>                | December 31, 2017 |               |               |                |
|-------------------------------------|-------------------|---------------|---------------|----------------|
|                                     | Level 1           | Level 2       | Level 3       | Total          |
| <b>Derivative assets</b>            |                   |               |               |                |
| Natural gas contracts               | \$ 1.8            | \$ 3.9        | \$ —          | \$ 5.7         |
| Petroleum products contracts        | 1.2               | —             | —             | 1.2            |
| FTRs                                | —                 | —             | 4.4           | 4.4            |
| Coal contracts                      | —                 | 1.1           | —             | 1.1            |
| <b>Total derivative assets</b>      | <b>\$ 3.0</b>     | <b>\$ 5.0</b> | <b>\$ 4.4</b> | <b>\$ 12.4</b> |
| Investments held in rabbi trust     | \$ 120.7          | \$ —          | \$ —          | \$ 120.7       |
| <b>Derivative liabilities</b>       |                   |               |               |                |
| Natural gas contracts               | \$ 7.0            | \$ 3.8        | \$ —          | \$ 10.8        |
| Coal contracts                      | —                 | 0.8           | —             | 0.8            |
| <b>Total derivative liabilities</b> | <b>\$ 7.0</b>     | <b>\$ 4.6</b> | <b>\$ —</b>   | <b>\$ 11.6</b> |

| <i>(in millions)</i>                | December 31, 2016 |                |               |                |
|-------------------------------------|-------------------|----------------|---------------|----------------|
|                                     | Level 1           | Level 2        | Level 3       | Total          |
| <b>Derivative assets</b>            |                   |                |               |                |
| Natural gas contracts               | \$ 10.1           | \$ 24.2        | \$ —          | \$ 34.3        |
| Petroleum products contracts        | 0.2               | —              | —             | 0.2            |
| FTRs                                | —                 | —              | 5.1           | 5.1            |
| Coal contracts                      | —                 | 2.0            | —             | 2.0            |
| <b>Total derivative assets</b>      | <b>\$ 10.3</b>    | <b>\$ 26.2</b> | <b>\$ 5.1</b> | <b>\$ 41.6</b> |
| Investments held in rabbi trust     | \$ 103.9          | \$ —           | \$ —          | \$ 103.9       |
| <b>Derivative liabilities</b>       |                   |                |               |                |
| Natural gas contracts               | \$ 0.2            | \$ 0.2         | \$ —          | \$ 0.4         |
| Petroleum products contracts        | 0.1               | —              | —             | 0.1            |
| Coal contracts                      | —                 | 1.9            | —             | 1.9            |
| <b>Total derivative liabilities</b> | <b>\$ 0.3</b>     | <b>\$ 2.1</b>  | <b>\$ —</b>   | <b>\$ 2.4</b>  |

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. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets. See Note 15, Derivative Instruments, for more information.

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

| <i>(in millions)</i>                    | 2017          | 2016          | 2015          |
|---|---------------|---------------|---------------|
| Balance at the beginning of the period  | \$ 5.1        | \$ 3.6        | \$ 7.0        |
| Realized and unrealized (losses) gains  | —             | (0.2)         | 1.3           |
| Purchases                               | 13.8          | 15.2          | 3.9           |
| Sales                                   | —             | (0.2)         | (0.1)         |
| Settlements                             | (14.5)        | (13.3)        | (11.9)        |
| Acquisition of Integrys                 | —             | —             | (1.3)         |
| Transfers out of level 3                | —             | —             | 4.7           |
| <b>Balance at the end of the period</b> | <b>\$ 4.4</b> | <b>\$ 5.1</b> | <b>\$ 3.6</b> |

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through cost of sales on the income statements.

## Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

| <i>(in millions)</i>                        | 2017            |            | 2016            |            |
|---|-----------------|------------|-----------------|------------|
|   | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Preferred stock                             | \$ 30.4         | \$ 30.5    | \$ 30.4         | \$ 28.8    |
| Long-term debt, including current portion * | 9,561.7         | 10,341.9   | 9,285.8         | 9,818.2    |

\* The carrying amount of long-term debt excludes capital lease obligations of \$27.0 million and \$29.6 million at December 31, 2017 and December 31, 2016, respectively.

## NOTE 15—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

| <i>(in millions)</i>         | December 31, 2017 |                        | December 31, 2016 |                        |
|------------------------------|-------------------|------------------------|-------------------|------------------------|
|                              | Derivative Assets | Derivative Liabilities | Derivative Assets | Derivative Liabilities |
| <b>Other current</b>         |                   |                        |                   |                        |
| Natural gas contracts        | \$ 5.6            | \$ 9.4                 | \$ 31.4           | \$ 0.4                 |
| Petroleum products contracts | 1.2               | —                      | 0.2               | 0.1                    |
| FTRs                         | 4.4               | —                      | 5.1               | —                      |
| Coal contracts               | 0.6               | 0.6                    | 1.5               | 1.4                    |
| <b>Total other current</b>   | <b>\$ 11.8</b>    | <b>\$ 10.0</b>         | <b>\$ 38.2</b>    | <b>\$ 1.9</b>          |
| <b>Other long-term</b>       |                   |                        |                   |                        |
| Natural gas contracts        | \$ 0.1            | \$ 1.4                 | \$ 2.9            | \$ —                   |
| Coal contracts               | 0.5               | 0.2                    | 0.5               | 0.5                    |
| <b>Total other long-term</b> | <b>\$ 0.6</b>     | <b>\$ 1.6</b>          | <b>\$ 3.4</b>     | <b>\$ 0.5</b>          |
| <b>Total</b>                 | <b>\$ 12.4</b>    | <b>\$ 11.6</b>         | <b>\$ 41.6</b>    | <b>\$ 2.4</b>          |

Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

| <i>(in millions)</i>         | December 31, 2017 |                | December 31, 2016 |                  | December 31, 2015 |                  |
|------------------------------|-------------------|----------------|-------------------|------------------|-------------------|------------------|
|                              | Volume            | Gains (Losses) | Volume            | Gains (Losses)   | Volume            | Gains (losses)   |
| Natural gas contracts        | 123.1 Dth         | \$ (8.0)       | 151.1 Dth         | \$ (59.6)        | 86.2 Dth          | \$ (50.5)        |
| Petroleum products contracts | 18.0 gallons      | (1.3)          | 14.7 gallons      | (3.2)            | 7.8 gallons       | (1.9)            |
| FTRs                         | 36.2 MWh          | 14.0           | 33.7 MWh          | 13.3             | 27.3 MWh          | 6.7              |
| <b>Total</b>                 |                   | <b>\$ 4.7</b>  |                   | <b>\$ (49.5)</b> |                   | <b>\$ (45.7)</b> |

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

| <i>(in millions)</i>                         | December 31, 2017 |                        | December 31, 2016    |                        |
|--|-------------------|------------------------|----------------------|------------------------|
|  | Derivative Assets | Derivative Liabilities | Derivative Assets    | Derivative Liabilities |
| Gross amount recognized on the balance sheet | \$ 12.4           | \$ 11.6                | \$ 41.6              | \$ 2.4                 |
| Gross amount not offset on the balance sheet | (4.9)             | (9.0) <sup>(1)</sup>   | (4.9) <sup>(2)</sup> | (0.5)                  |
| <b>Net amount</b>                            | <b>\$ 7.5</b>     | <b>\$ 2.6</b>          | <b>\$ 36.7</b>       | <b>\$ 1.9</b>          |

(1) Includes cash collateral posted of \$4.1 million.

(2) Includes cash collateral received of \$4.4 million.

At December 31, 2017 and 2016, we had posted cash collateral of \$16.2 million and \$16.4 million, respectively, in our margin accounts. At December 31, 2016, we had also received cash collateral of \$4.4 million in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2017 and 2016 was \$3.7 million and \$0.2 million, respectively. At December 31, 2017 and 2016, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2017, we would have been required to post collateral of \$2.7 million. At December 31, 2016, we would not have been required to post any collateral.

During 2015, we settled several forward interest rate swap agreements entered into to mitigate interest rate risk associated with the issuance of \$1.2 billion of long-term debt related to the acquisition of Integrys. As these agreements qualified for cash flow hedge accounting treatment, the proceeds of \$19.0 million received upon settlement were deferred in accumulated other comprehensive income and are being amortized as a decrease to interest expense over the periods in which the interest costs are recognized in earnings.

For the years ended December 31, 2017, 2016, and 2015, we reclassified \$2.2 million, \$2.2 million, and \$1.2 million, respectively, of forward interest rate swap agreement settlements deferred in accumulated other comprehensive income as a reduction to interest expense. We estimate that during the next twelve months, \$2.2 million will be reclassified from accumulated other comprehensive income as a reduction to interest expense.

## NOTE 16—GUARANTEES

The following table shows our outstanding guarantees:

| (in millions)  | Total Amounts Committed at<br>December 31, 2017 | Expiration          |               |                |
|--|---|---------------------|---------------|----------------|
|  |   | Less Than 1<br>Year | 1 to 3 Years  | Over 3 Years   |
| Guarantees supporting commodity transactions of subsidiaries (1) | \$ 8.1  | \$ 8.1              | \$ —          | \$ —           |
| Standby letters of credit (2)                                    | 55.1  | 54.7                | 0.4           | —              |
| Surety bonds (3)   | 9.7   | 9.7                 | —             | —              |
| Other guarantees (4)   | 10.9  | 0.5                 | —             | 10.4           |
| <b>Total guarantees</b>  | <b>\$ 83.8</b>                                  | <b>\$ 73.0</b>      | <b>\$ 0.4</b> | <b>\$ 10.4</b> |

(1) Consists of \$8.1 million to support the business operations of Bluewater.

(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 \$10.9 million related to other indemnifications, for which a liability of \$10.4 million related to workers compensation coverage was recorded on our balance sheets.

## NOTE 17—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.

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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 receive a 6% 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:

| <i>(in millions)</i>                       | Pension Costs     |                   | OPEB Costs      |                  |
|--|-------------------|-------------------|-----------------|------------------|
|  | 2017              | 2016              | 2017            | 2016             |
| <b>Change in benefit obligation</b>        |                   |                   |                 |                  |
| Obligation at January 1                    | \$ 3,058.8        | \$ 3,083.0        | \$ 818.4        | \$ 842.0         |
| Service cost                               | 44.6              | 45.4              | 24.1            | 26.1             |
| Interest cost                              | 121.8             | 130.8             | 32.9            | 37.0             |
| Participant contributions                  | —                 | —                 | 13.4            | 16.4             |
| Plan amendments                            | —                 | (3.0)             | (36.4)          | (18.9)           |
| Actuarial loss (gain)                      | 162.6             | 71.7              | 12.9            | (36.5)           |
| Benefit payments                           | (224.1)           | (269.1)           | (48.8)          | (49.1)           |
| Federal subsidy on benefits paid           | N/A               | N/A               | 2.0             | 1.4              |
| <b>Obligation at December 31</b>           | <b>\$ 3,163.7</b> | <b>\$ 3,058.8</b> | <b>\$ 818.5</b> | <b>\$ 818.4</b>  |
| <b>Change in fair value of plan assets</b> |                   |                   |                 |                  |
| Fair value at January 1                    | \$ 2,709.2        | \$ 2,755.1        | \$ 773.5        | \$ 749.8         |
| Actual return on plan assets               | 368.7             | 199.4             | 95.9            | 51.5             |
| Employer contributions                     | 113.0             | 23.8              | 7.5             | 4.9              |
| Participant contributions                  | —                 | —                 | 13.4            | 16.4             |
| Benefit payments                           | (224.1)           | (269.1)           | (48.8)          | (49.1)           |
| <b>Fair value at December 31</b>           | <b>\$ 2,966.8</b> | <b>\$ 2,709.2</b> | <b>\$ 841.5</b> | <b>\$ 773.5</b>  |
| <b>Funded status at December 31</b>        | <b>\$ (196.9)</b> | <b>\$ (349.6)</b> | <b>\$ 23.0</b>  | <b>\$ (44.9)</b> |

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

| <i>(in millions)</i>                  | Pension Costs     |                   | OPEB Costs     |                  |
|---------------------------------------|-------------------|-------------------|----------------|------------------|
|                                       | 2017              | 2016              | 2017           | 2016             |
| Other long-term assets                | \$ 143.0          | \$ 74.4           | \$ 80.5        | \$ 29.7          |
| Pension and OPEB obligations          | 339.9             | 424.0             | 57.5           | 74.6             |
| <b>Total net (liabilities) assets</b> | <b>\$ (196.9)</b> | <b>\$ (349.6)</b> | <b>\$ 23.0</b> | <b>\$ (44.9)</b> |

The accumulated benefit obligation for all defined benefit pension plans was \$3,057.7 million and \$2,939.9 million as of December 31, 2017 and 2016, 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:

| <i>(in millions)</i>           | 2017     | 2016       |
|--------------------------------|----------|------------|
| Projected benefit obligation   | \$ 679.5 | \$ 1,667.0 |
| Accumulated benefit obligation | 630.3    | 1,549.5    |
| Fair value of plan assets      | 339.6    | 1,242.9    |

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

| <i>(in millions)</i>                                      | Pension Costs     |                   | OPEB Costs        |                  |
|---|-------------------|-------------------|-------------------|------------------|
|   | 2017              | 2016              | 2017              | 2016             |
| <b>Accumulated other comprehensive loss (pre-tax) (1)</b> |                   |                   |                   |                  |
| Net actuarial loss (gain)                                 | \$ 10.0           | \$ 12.0           | \$ (1.0)          | \$ (1.0)         |
| Prior service credits                                     | —                 | —                 | (0.1)             | —                |
| <b>Total</b>  | <b>\$ 10.0</b>    | <b>\$ 12.0</b>    | <b>\$ (1.1)</b>   | <b>\$ (1.0)</b>  |
| <b>Net regulatory assets (2)</b>                          |                   |                   |                   |                  |
| Net actuarial loss (gain)                                 | \$ 1,136.8        | \$ 1,240.7        | \$ (4.7)          | \$ 25.8          |
| Prior service costs (credits)                             | 7.5               | 10.5              | (111.8)           | (87.9)           |
| <b>Total</b>  | <b>\$ 1,144.3</b> | <b>\$ 1,251.2</b> | <b>\$ (116.5)</b> | <b>\$ (62.1)</b> |

(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 2018:

| <i>(in millions)</i>                       | Pension Costs  | OPEB Costs       |
|--|----------------|------------------|
| Net actuarial loss                         | \$ 92.5        | \$ 1.3           |
| Prior service costs (credits)              | 2.6            | (15.3)           |
| <b>Total 2018 – estimated amortization</b> | <b>\$ 95.1</b> | <b>\$ (14.0)</b> |

The components of net periodic benefit cost (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

| <i>(in millions)</i>                        | Pension Costs  |                |                | OPEB Costs      |               |               |
|---|----------------|----------------|----------------|-----------------|---------------|---------------|
|   | 2017           | 2016           | 2015           | 2017            | 2016          | 2015          |
| Service cost                                | \$ 44.6        | \$ 45.4        | \$ 30.4        | \$ 24.1         | \$ 26.1       | \$ 20.7       |
| Interest cost                               | 121.8          | 130.8          | 94.3           | 32.9            | 37.0          | 26.7          |
| Expected return on plan assets              | (195.7)        | (195.9)        | (155.6)        | (55.5)          | (52.7)        | (39.6)        |
| Plan settlement                             | 9.0            | 16.5           | —              | —               | —             | —             |
| Plan curtailment                            | —              | —              | (0.3)          | —               | —             | —             |
| Amortization of prior service cost (credit) | 2.9            | 3.4            | 2.2            | (12.3)          | (9.4)         | (6.4)         |
| Amortization of net actuarial loss          | 86.1           | 82.9           | 68.5           | 3.1             | 8.5           | 3.9           |
| <b>Net periodic benefit cost (credit)</b>   | <b>\$ 68.7</b> | <b>\$ 83.1</b> | <b>\$ 39.5</b> | <b>\$ (7.7)</b> | <b>\$ 9.5</b> | <b>\$ 5.3</b> |

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

|   | Pension |       | OPEB  |       |
|---|---------|-------|-------|-------|
|   | 2017    | 2016  | 2017  | 2016  |
| Discount rate                                 | 3.66%   | 4.16% | 3.63% | 4.14% |
| Rate of compensation increase                 | 3.61%   | 3.60% | N/A   | N/A   |
| Assumed medical cost trend rate (Pre 65)      | N/A     | N/A   | 6.50% | 7.00% |
| Ultimate trend rate (Pre 65)                  | N/A     | N/A   | 5.00% | 5.00% |
| Year ultimate trend rate is reached (Pre 65)  | N/A     | N/A   | 2024  | 2021  |
| Assumed medical cost trend rate (Post 65)     | N/A     | N/A   | 6.09% | 7.00% |
| 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  | 2021  |

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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 Costs |       |       |
|--------------------------------|---------------|-------|-------|
|                                | 2017          | 2016  | 2015  |
| Discount rate                  | 4.11%         | 4.35% | 4.11% |
| Expected return on plan assets | 7.11%         | 7.12% | 7.37% |
| Rate of compensation increase  | 3.60%         | 3.75% | 4.00% |

|  | OPEB Costs |       |       |
|--|------------|-------|-------|
|  | 2017       | 2016  | 2015  |
| Discount rate                                    | 4.04%      | 4.38% | 4.09% |
| Expected return on plan assets                   | 7.25%      | 7.25% | 7.54% |
| Assumed medical cost trend rate (Pre 65/Post 65) | 7.00%      | 7.50% | 7.50% |
| Ultimate trend rate                              | 5.00%      | 5.00% | 5.00% |
| Year ultimate trend rate is reached              | 2021       | 2021  | 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 2018, the expected return on assets assumption is 7.12% for the pension plans and 7.25% 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, 2017, 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 | \$ 8.0      | \$ (6.4)    |
| Effect on health care component of the accumulated postretirement benefit obligations                           | 76.2        | (62.5)      |

## 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 legacy Wisconsin Energy Corporation OPEB trusts' target asset allocations are 60% equity investments and 40% fixed income investments. The two largest legacy OPEB trusts for Integrys have target asset allocations of 45% equity investments and 55% fixed income, and 50% equity investments and 50% fixed income, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies primarily located in the United States. 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.

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The following tables provide the fair values of our investments by asset class:

| December 31, 2017                       |                     |                   |                 |                   |                 |                 |               |                 |  |
|---|---------------------|-------------------|-----------------|-------------------|-----------------|-----------------|---------------|-----------------|--|
| (in millions)                           | Pension Plan Assets |                   |                 |                   | OPEB Assets     |                 |               |                 |  |
|   | Level 1             | Level 2           | Level 3         | Total             | Level 1         | Level 2         | Level 3       | Total           |  |
| <b>Asset Class</b>                      |                     |                   |                 |                   |                 |                 |               |                 |  |
| Cash and cash equivalents               | \$ —                | \$ 53.6           | \$ —            | \$ 53.6           | \$ 19.6         | \$ 2.3          | \$ —          | \$ 21.9         |  |
| Equity securities:                      |                     |                   |                 |                   |                 |                 |               |                 |  |
| United States Equity                    | 345.0               | 0.1               | —               | 345.1             | 101.0           | —               | —             | 101.0           |  |
| International Equity                    | 352.1               | —                 | 0.8             | 352.9             | 115.3           | —               | 0.2           | 115.5           |  |
| Fixed income securities: *              |                     |                   |                 |                   |                 |                 |               |                 |  |
| United States Bonds                     | 138.6               | 892.9             | —               | 1,031.5           | 121.0           | 148.1           | —             | 269.1           |  |
| International Bonds                     | 17.8                | 86.8              | —               | 104.6             | 7.2             | 9.1             | —             | 16.3            |  |
| Private Equity and Real Estate          | —                   | 154.1             | 100.1           | 254.2             | —               | 6.6             | 7.7           | 14.3            |  |
|   | \$ 853.5            | \$ 1,187.5        | \$ 100.9        | \$ 2,141.9        | \$ 364.1        | \$ 166.1        | \$ 7.9        | \$ 538.1        |  |
| Investments measured at net asset value |                     |                   |                 | \$ 824.9          |                 |                 |               | \$ 303.4        |  |
| <b>Total</b>                            | <b>\$ 853.5</b>     | <b>\$ 1,187.5</b> | <b>\$ 100.9</b> | <b>\$ 2,966.8</b> | <b>\$ 364.1</b> | <b>\$ 166.1</b> | <b>\$ 7.9</b> | <b>\$ 841.5</b> |  |

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

| December 31, 2016                       |                     |                 |                |                   |                |                 |               |                 |  |
|---|---------------------|-----------------|----------------|-------------------|----------------|-----------------|---------------|-----------------|--|
| (in millions)                           | Pension Plan Assets |                 |                |                   | OPEB Assets    |                 |               |                 |  |
|   | Level 1             | Level 2         | Level 3        | Total             | Level 1        | Level 2         | Level 3       | Total           |  |
| <b>Asset Class</b>                      |                     |                 |                |                   |                |                 |               |                 |  |
| Cash and cash equivalents               | \$ 3.7              | \$ 58.0         | \$ —           | \$ 61.7           | \$ 28.8        | \$ 3.4          | \$ —          | \$ 32.2         |  |
| Equity securities:                      |                     |                 |                |                   |                |                 |               |                 |  |
| United States Equity                    | 273.9               | 0.1             | —              | 274.0             | 34.3           | —               | —             | 34.3            |  |
| International Equity                    | 54.1                | 0.6             | —              | 54.7              | 3.5            | 0.2             | —             | 3.7             |  |
| Fixed income securities: *              |                     |                 |                |                   |                |                 |               |                 |  |
| United States Bonds                     | —                   | 861.3           | 0.8            | 862.1             | —              | 137.9           | —             | 137.9           |  |
| International Bonds                     | —                   | 75.9            | —              | 75.9              | —              | 8.8             | —             | 8.8             |  |
| Private Equity and Real Estate          | —                   | —               | 14.6           | 14.6              | —              | —               | 1.3           | 1.3             |  |
|   | \$ 331.7            | \$ 995.9        | \$ 15.4        | \$ 1,343.0        | \$ 66.6        | \$ 150.3        | \$ 1.3        | \$ 218.2        |  |
| Investments measured at net asset value |                     |                 |                | \$ 1,366.2        |                |                 |               | \$ 555.3        |  |
| <b>Total</b>                            | <b>\$ 331.7</b>     | <b>\$ 995.9</b> | <b>\$ 15.4</b> | <b>\$ 2,709.2</b> | <b>\$ 66.6</b> | <b>\$ 150.3</b> | <b>\$ 1.3</b> | <b>\$ 773.5</b> |  |

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

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

| (in millions)                              | Private Equity and Real Estate |               | International Equity |               | U.S. Bonds  |
|--|--------------------------------|---------------|----------------------|---------------|-------------|
|  | Pension                        | OPEB          | Pension              | OPEB          | Pension     |
| Beginning balance at January 1, 2017       | \$ 14.6                        | \$ 1.3        | \$ —                 | \$ —          | \$ 0.8      |
| Realized and unrealized gains (losses)     | 2.8                            | 0.3           | (0.2)                | —             | (0.8)       |
| Purchases                                  | 55.5                           | 3.6           | 1.0                  | 0.2           | —           |
| Transfers into level 3                     | 27.2                           | 2.5           | —                    | —             | —           |
| <b>Ending balance at December 31, 2017</b> | <b>\$ 100.1</b>                | <b>\$ 7.7</b> | <b>\$ 0.8</b>        | <b>\$ 0.2</b> | <b>\$ —</b> |

| <i>(in millions)</i>                       | Private Equity and Real Estate |               | U.S. Bonds    |
|--|--------------------------------|---------------|---------------|
|  | Pension                        | OPEB          | Pension       |
| Beginning balance at January 1, 2016       | \$ 5.5                         | \$ 0.4        | \$ —          |
| Realized and unrealized gains              | 0.5                            | 0.1           | —             |
| Purchases                                  | 8.6                            | 0.8           | 0.8           |
| <b>Ending balance at December 31, 2016</b> | <b>\$ 14.6</b>                 | <b>\$ 1.3</b> | <b>\$ 0.8</b> |

## Cash Flows

We expect to contribute \$12.2 million to the pension plans and \$0.9 million to the OPEB plans in 2018, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB:

| <i>(in millions)</i> | Pension Costs | OPEB Costs |
|----------------------|---------------|------------|
| 2018                 | \$ 234.3      | \$ 44.2    |
| 2019                 | 233.4         | 46.3       |
| 2020                 | 236.3         | 46.6       |
| 2021                 | 233.4         | 48.1       |
| 2022                 | 220.3         | 49.4       |
| 2023-2027            | 1,026.8       | 258.2      |

## 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. Certain employees participate in a defined contribution pension plan, 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 \$47.9 million, \$44.3 million, and \$48.0 million in 2017, 2016, and 2015, respectively.

## NOTE 18—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 an eleven-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 less than 10% of the voting control. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

| <i>(in millions)</i>                               | 2017              |                |                   |
|--|-------------------|----------------|-------------------|
|  | ATC               | ATC Holdco     | Total             |
| Balance at January 1                               | \$ 1,443.9        | \$ —           | \$ 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 *           | —              | 154.2             |
| Less: Other  | 0.2               | —              | 0.2               |
| <b>Balance at December 31</b>                      | <b>\$ 1,515.8</b> | <b>\$ 37.6</b> | <b>\$ 1,553.4</b> |

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

| <i>(in millions)</i>  | ATC                  |                   |
|---|----------------------|-------------------|
|   | 2016                 | 2015              |
| Balance at January 1  | \$ 1,380.9           | \$ 424.1          |
| Add: Earnings from equity method investment                                 | 146.5                | 96.1              |
| Add: Capital contributions  | 42.3                 | 8.7               |
| Add: Acquisition of Integrys's investment in ATC                            | (1.0)                | 541.5             |
| Add: Equity method goodwill from the acquisition of Integrys <sup>(1)</sup> | 10.4                 | 395.8             |
| Less: Distributions   | 135.1 <sup>(2)</sup> | 85.1              |
| Less: Other   | 0.1                  | 0.2               |
| <b>Balance at December 31</b>   | <b>\$ 1,443.9</b>    | <b>\$ 1,380.9</b> |

(1) Represents the purchase price allocated to Integrys's investment in ATC in excess of the recorded value.

(2) Of this amount, \$35.2 million was recorded as a receivable from ATC in other current assets at December 31, 2016.

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:

| <i>(in millions)</i>                               | 2017    | 2016    | 2015    |
|--|---------|---------|---------|
| Charges to ATC for services and construction       | \$ 17.1 | \$ 18.5 | \$ 15.4 |
| Charges from ATC for network transmission services | 349.3   | 357.3   | 289.2   |
| Refund from ATC per FERC ROE order                 | (28.3)  | —       | —       |

As of December 31, 2017 and 2016, our balance sheets included the following receivables and payables related to ATC:

| <i>(in millions)</i>          | 2017   | 2016   |
|-------------------------------|--------|--------|
| Accounts receivable           |        |        |
| Services provided to ATC      | \$ 1.5 | \$ 2.2 |
| Other current assets          |        |        |
| Dividends receivable from ATC | 39.9   | 35.2   |
| Accounts payable              |        |        |
| Services received from ATC    | 31.2   | 28.7   |

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

| <i>(in millions)</i>         | 2017            | 2016            | 2015            |
|------------------------------|-----------------|-----------------|-----------------|
| <b>Income statement data</b> |                 |                 |                 |
| Revenues                     | \$ 721.7        | \$ 650.8        | \$ 615.8        |
| Operating expenses           | 345.0           | 322.5           | 319.3           |
| Other expense                | 104.1           | 95.5            | 96.1            |
| <b>Net income</b>            | <b>\$ 272.6</b> | <b>\$ 232.8</b> | <b>\$ 200.4</b> |

| <i>(in millions)</i>                              | December 31, 2017 | December 31, 2016 |
|---|-------------------|-------------------|
| <b>Balance sheet data</b>                         |                   |                   |
| Current assets                                    | \$ 87.7           | \$ 75.8           |
| Noncurrent assets                                 | 4,598.9           | 4,312.9           |
| <b>Total assets</b>                               | <b>\$ 4,686.6</b> | <b>\$ 4,388.7</b> |
| Current liabilities                               | \$ 767.2          | \$ 495.1          |
| Long-term debt                                    | 1,790.6           | 1,865.3           |
| Other noncurrent liabilities                      | 240.3             | 271.5             |
| Shareholders' equity                              | 1,888.5           | 1,756.8           |
| <b>Total liabilities and shareholders' equity</b> | <b>\$ 4,686.6</b> | <b>\$ 4,388.7</b> |

## NOTE 19—SEGMENT INFORMATION

At December 31, 2017, we reported six segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, WPS, and U MERC.
- 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, electric transmission company regulated by the FERC and certain state regulatory commissions.
- Following the acquisition of Bluewater, our We Power segment was renamed the non-utility energy infrastructure segment. This segment includes We Power, which owns and leases generating facilities to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. See Note 2, Acquisitions, for more information on the Bluewater transaction.
- 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, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. 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, 2017, 2016, and 2015.

| <b>2017 (in millions)</b>                     | <b>Utility Operations</b> |                 |                     |                                 | <b>Electric Transmission</b> | <b>Non-Utility Energy Infrastructure</b> | <b>Corporate and Other</b> | <b>Reconciling Eliminations</b> | <b>WEC Energy Group Consolidated</b> |
|---|---------------------------|-----------------|---------------------|---------------------------------|------------------------------|--|----------------------------|---------------------------------|--------------------------------------|
|   | <b>Wisconsin</b>          | <b>Illinois</b> | <b>Other States</b> | <b>Total Utility Operations</b> |                              |  |                            |                                 |                                      |
| 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               | 1,912.5                   | 471.1           | 101.3               | 2,484.9                         | —                            | 7.3                                      | (4.1)                      | (441.1)                         | 2,047.0                              |
| Depreciation and amortization                 | 523.9                     | 152.6           | 24.8                | 701.3                           | —                            | 71.4                                     | 25.9                       | —                               | 798.6                                |
| Operating income (loss)                       | 1,065.9                   | 273.0           | 54.2                | 1,393.1                         | —                            | 400.5                                    | (8.4)                      | —                               | 1,785.2                              |
| 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.

| 2016 (in millions)                            | Utility Operations |            |              |                          | Electric Transmission | Non-Utility Energy Infrastructure | Corporate and Other | Reconciling Eliminations | WEC Energy Group Consolidated |
|---|--------------------|------------|--------------|--------------------------|-----------------------|-----------------------------------|---------------------|--------------------------|-------------------------------|
|   | Wisconsin          | Illinois   | Other States | Total Utility Operations |                       |                                   |                     |                          |                               |
| External revenues                             | \$ 5,805.4         | \$ 1,242.2 | \$ 376.5     | \$ 7,424.1               | \$ —                  | \$ 24.9                           | \$ 23.3             | \$ —                     | \$ 7,472.3                    |
| Intersegment revenues                         | 0.3                | —          | —            | 0.3                      | —                     | 423.3                             | —                   | (423.6)                  | —                             |
| Other operation and maintenance               | 2,025.4            | 485.1      | 110.1        | 2,620.6                  | —                     | 4.3                               | (15.8)              | (423.6)                  | 2,185.5                       |
| Depreciation and amortization                 | 496.6              | 134.0      | 21.1         | 651.7                    | —                     | 68.3                              | 42.6                | —                        | 762.6                         |
| Operating income (loss)                       | 1,027.0            | 239.6      | 49.9         | 1,316.5                  | —                     | 375.6                             | (10.0)              | —                        | 1,682.1                       |
| Equity in earnings of transmission affiliates | —                  | —          | —            | —                        | 146.5                 | —                                 | —                   | —                        | 146.5                         |
| Interest expense                              | 180.9              | 38.9       | 8.5          | 228.3                    | —                     | 62.1                              | 120.9               | (8.6)                    | 402.7                         |
| Capital expenditures                          | 910.9              | 293.2      | 59.5         | 1,263.6                  | —                     | 62.3                              | 97.8                | —                        | 1,423.7                       |
| Total assets *                                | 21,730.7           | 5,714.6    | 995.1        | 28,440.4                 | 1,476.9               | 2,777.1                           | 778.0               | (3,349.2)                | 30,123.2                      |

\* Total assets at December 31, 2016 reflect an elimination of \$2,029.5 million for all lease activity between We Power and WE.

| 2015 (in millions)                            | Utility Operations |          |              |                          | Electric Transmission | Non-Utility Energy Infrastructure | Corporate and Other | Reconciling Eliminations | WEC Energy Group Consolidated |
|---|--------------------|----------|--------------|--------------------------|-----------------------|-----------------------------------|---------------------|--------------------------|-------------------------------|
|   | Wisconsin          | Illinois | Other States | Total Utility Operations |                       |                                   |                     |                          |                               |
| External revenues                             | \$ 5,186.1         | \$ 503.4 | \$ 149.3     | \$ 5,838.8               | \$ —                  | \$ 40.0                           | \$ 47.3             | \$ —                     | \$ 5,926.1                    |
| Intersegment revenues                         | 5.0                | —        | —            | 5.0                      | —                     | 405.2                             | —                   | (410.2)                  | —                             |
| Other operation and maintenance               | 1,741.0            | 219.6    | 50.0         | 2,010.6                  | —                     | 4.3                               | 103.7               | (409.3)                  | 1,709.3                       |
| Depreciation and amortization                 | 408.6              | 63.3     | 10.0         | 481.9                    | —                     | 67.5                              | 12.4                | —                        | 561.8                         |
| Operating income (loss)                       | 884.2              | 78.1     | 6.0          | 968.3                    | —                     | 373.4                             | (91.2)              | —                        | 1,250.5                       |
| Equity in earnings of transmission affiliates | —                  | —        | —            | —                        | 96.1                  | —                                 | —                   | —                        | 96.1                          |
| Interest expense                              | 157.1              | 19.9     | 5.1          | 182.1                    | —                     | 63.4                              | 91.0                | (5.1)                    | 331.4                         |
| Capital expenditures                          | 950.3              | 194.4    | 34.7         | 1,179.4                  | —                     | 53.4                              | 33.4                | —                        | 1,266.2                       |
| Total assets *                                | 21,113.5           | 5,462.9  | 918.0        | 27,494.4                 | 1,381.0               | 2,779.0                           | 1,132.5             | (3,431.7)                | 29,355.2                      |

\* Total assets at December 31, 2015 reflect an elimination of \$2,105.3 million for all lease activity between We Power and WE.

## NOTE 20—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 that 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. We account for ATC as an equity method investment. The significant assets and liabilities



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related to ATC recorded on our balance sheets were our equity investment, distributions receivable, and accounts payable. At December 31, 2017 and 2016, our equity investment was \$1,515.8 million and \$1,443.9 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC. In addition, we had receivables of \$39.9 million and \$35.2 million recorded at December 31, 2017 and 2016, respectively, for distributions from ATC. We also had \$31.2 million and \$28.7 million of accounts payable due to ATC at December 31, 2017 and 2016, respectively, for network transmission services.

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 that 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. We account for ATC Holdco as an equity method investment. The only significant asset or liability related to ATC Holdco recorded on our balance sheets was our equity investment of \$37.6 million at December 31, 2017. This amount approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 18, Investment in Transmission Affiliates, for more information.

### Purchased Power Agreement

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

We have approximately \$71.4 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under this contract for the years ended December 31, 2017, 2016, and 2015, were \$18.0 million, \$54.2 million, and \$53.6 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

### NOTE 21—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, operating leases, environmental matters, and enforcement and litigation matters.

#### Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2017, including those of our subsidiaries.

| (in millions)                                 | Date Contracts<br>Extend Through | Total Amounts<br>Committed | Payments Due By Period |                 |                 |                 |                 | Later<br>Years    |
|---|----------------------------------|----------------------------|------------------------|-----------------|-----------------|-----------------|-----------------|-------------------|
|   |                                  |                            | 2018                   | 2019            | 2020            | 2021            | 2022            |                   |
| Electric utility:                             |                                  |                            |                        |                 |                 |                 |                 |                   |
| Nuclear                                       | 2033                             | \$ 9,184.5                 | \$ 420.1               | \$ 445.4        | \$ 475.1        | \$ 501.1        | \$ 531.2        | \$ 6,811.6        |
| Purchased power                               | 2027                             | 645.3                      | 109.3                  | 73.5            | 72.8            | 68.9            | 62.1            | 258.7             |
| Coal supply and transportation                | 2024                             | 341.2                      | 223.3                  | 72.0            | 38.8            | 2.1             | 2.1             | 2.9               |
| Natural gas utility supply and transportation | 2043                             | 1,469.9                    | 331.5                  | 294.6           | 219.2           | 123.3           | 78.9            | 422.4             |
| <b>Total</b>                                  |                                  | <b>\$ 11,640.9</b>         | <b>\$ 1,084.2</b>      | <b>\$ 885.5</b> | <b>\$ 805.9</b> | <b>\$ 695.4</b> | <b>\$ 674.3</b> | <b>\$ 7,495.6</b> |

## Operating Leases

We lease property, plant, and equipment under various terms. The operating leases generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value, or (b) exercise a renewal option, as set forth in the lease agreement.

Rental expense attributable to operating leases was \$13.2 million, \$15.1 million, and \$12.7 million in 2017, 2016, and 2015, respectively.

Future minimum payments under noncancelable operating leases are payable as follows:

| Year Ending December 31 | Payments<br>(in millions) |
|-------------------------|---------------------------|
| 2018                    | \$ 9.5                    |
| 2019                    | 9.2                       |
| 2020                    | 7.6                       |
| 2021                    | 7.2                       |
| 2022                    | 7.5                       |
| Later years             | 74.1                      |
| <b>Total</b>            | <b>\$ 115.1</b>           |

## 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<sub>2</sub>, NO<sub>x</sub>, fine particulates, mercury, and GHGs; water intake and discharges; disposal 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 old 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

### Sulfur Dioxide National Ambient Air Quality Standards

The EPA issued a revised 1-Hour SO<sub>2</sub> NAAQS that became effective in August 2010. The EPA issued a final rule in August 2015 describing the implementation requirements and established a compliance timeline for the revised standard. The final rule affords state agencies some latitude in rule implementation. A nonattainment designation could have negative impacts for a localized geographic area, including additional permitting requirements for new or existing sources in the area. In June 2016, we provided modeling to the WDNR that shows the area around the Weston power plant, located in Marathon County, Wisconsin, to be in compliance. In December 2017, the EPA finalized the designation, and Marathon County has been designated attainment. The EPA designated Marquette County, Michigan, where PIPP is located, as unclassified/attainment, effective September 1, 2016. We continue to believe that our fleet overall is well positioned to meet the regulation and do not expect to incur significant costs to comply with this regulation.

## 8-Hour Ozone 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. In December 2017, the EPA designated all the counties along Wisconsin's Lake Michigan shoreline, except Brown, Kewaunee, Marinette, and Oconto Counties, as either partial or full nonattainment. Waukesha and Washington counties were also included due to the counties being in the Milwaukee combined statistical area. For nonattainment areas, the state of Wisconsin will have to develop a state implementation plan to bring the areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020. Although we will not know the potential impacts for complying with the 2015 ozone NAAQS until the designations are final, which is expected from the EPA in April 2018, and until the state prepares a draft attainment plan, 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.

## Climate Change

In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan, a proposed federal plan and model trading rules as alternatives or guides to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In October 2015, following publication of the CPP, numerous states (including Wisconsin and Michigan) and other parties, filed lawsuits challenging the final rule, including a request to stay the implementation of the final rule pending the outcome of these legal challenges. The D.C. Circuit Court of Appeals denied the stay request, but in February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that further appellate review is sought, at the Supreme Court. The D.C. Circuit Court of Appeals heard one case in September 2016, and the other case is still pending. In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the cases to be held in abeyance. Supplemental briefs were provided addressing whether the cases should be remanded to the EPA rather than held in abeyance. The EPA argued that the cases should continue to be held in abeyance pending the conclusion of the EPA's review of the CPP and any resulting rulemaking.

The CPP seeks to achieve state-specific GHG emission reduction goals by 2030, and would have required states to submit plans by September 2016. The goal of the final rule is to reduce nationwide GHG emissions by 32% from 2005 levels. The rule is seeking GHG emission reductions in Wisconsin and Michigan of 41% and 39%, respectively, below 2012 levels by 2030. Interim goals starting in 2022 would require states to achieve about two-thirds of the 2030 required reduction.

In March 2017, President Trump issued an executive order that, among other things, specifically directs the EPA to review, and if appropriate, initiate proceedings to suspend, revise, or rescind the CPP and related GHG regulations for new, reconstructed, or modified fossil-fueled power plants. As a result of this order and related EPA review, as well as the ongoing legal proceedings, the timelines for the GHG emission reduction goals and all other aspects of the CPP are uncertain. In April 2017, the EPA withdrew the proposed rule for a federal plan and model trading rules that were published in October 2015 for use in developing state plans to implement the CPP or for use in states where a plan is not submitted or approved. In October 2017, the EPA issued a proposed rulemaking to repeal the CPP. In December 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it is appropriate to replace the CPP. In addition, the Governor of Wisconsin issued an executive order in February 2016, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan to implement the CPP.

Notwithstanding the uncertain future of the CPP, and given current fuel and technology markets, we continue to evaluate opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions. Our plan is to work with our industry partners, environmental groups, and the State of Wisconsin, with a goal of reducing CO<sub>2</sub> emissions by approximately 40% below 2005 levels by 2030. We have implemented and continue to evaluate numerous options in order to meet our CO<sub>2</sub> reduction goal, such as increased use of existing natural gas combined cycle units, co-firing or switching to natural gas in existing coal-fired units, reduced operation or retirement of existing coal-fired units, addition of new renewable energy resources (wind, solar), and consideration of supply and demand-side energy efficiency and distributed generation. As a result of our generation reshaping plan, we expect to retire approximately 1,800 MW of coal generation by 2020, including Pleasant Prairie power plant, PIPP, Pulliam power plant, and the jointly-owned Edgewater Unit 4 generation units. See Note 5, Property, Plant, and Equipment, for more information. In addition, we are evaluating our goal, and possible subsequent actions, with respect to national and international efforts to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius.

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We are required to report our CO<sub>2</sub> equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2016, we reported aggregated CO<sub>2</sub> equivalent emissions of approximately 29.1 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO<sub>2</sub> equivalent emissions of approximately 29.2 million metric tonnes to the EPA for 2017. The level of CO<sub>2</sub> 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<sub>2</sub> equivalent amounts related to the natural gas that our natural gas utilities distribute and sell. For 2016, we reported aggregated CO<sub>2</sub> equivalent emissions of approximately 26.8 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO<sub>2</sub> equivalent emissions of approximately 26.4 million metric tonnes to the EPA for 2017.

## **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, which requires that the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts from both impingement (entrapping organisms on water intake screens) and entrainment (drawing organisms into water intake). 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.

Facility owners must select from seven compliance options available to meet the impingement mortality (IM) reduction standard. The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, for IM reduction over the next several years as facility permits are reissued. Based on our assessment, we believe that existing technologies at our generating facilities, except for Pulliam Units 7 and 8 and Weston Unit 2, satisfy the IM BTA requirements. We plan to retire Pulliam Units 7 and 8 as early as late 2018. Therefore, we are not planning to make alterations to the existing water intake at Pulliam Units 7 and 8. We do expect that limited studies will be required to support the future WDNR IM BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the IM BTA requirements based on low capacity use of the unit.

BTA determinations must also be made by the WDNR and MDEQ to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. We have received an EM BTA determination by the WDNR, with EPA concurrence, for our intake modification at VAPP. Due to our plans to retire Pulliam Units 7 and 8, PIPP, and Pleasant Prairie power plant, we do not believe that BTA determinations for EM will be necessary for these facilities. Although we currently believe that, other than Weston Unit 2, existing technologies at Weston Units 3 and 4, PWGS, and OC 5 through OC 8 satisfy the EM BTA requirements, BTA determinations to address EM reduction requirements will not be made until discharge permits are renewed for these facilities. Until that time, with the exception of Weston Units 3 and 4, which have existing cooling towers that meet EM BTA requirements, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at the other facilities. We also expect that limited studies to support WDNR EM BTA determinations will be conducted at the Weston facility. During 2018, we will continue to evaluate options to address the EM BTA requirements at these plants.

We have also provided information to the WDNR and the MDEQ about planned unit retirements. Based on discussions with the MDEQ, if we submit a signed certification stating that PIPP will be retired no later than the end of the next permit cycle (assumed to be October 1, 2023), the EM BTA requirements will be waived. We expect to submit the letter identifying the last operating date for PIPP to the MDEQ during 2018, ahead of when the agency begins processing our pending application for the National Pollutant Discharge Elimination System permit reissuance. For Pulliam Units 7 and 8, we submitted our 2016 and 2017 entrainment studies to the WDNR in December 2017, with the application to renew our existing discharge permit.

We believe our fleet overall is well positioned to meet the new regulation and do not expect to incur significant costs to comply with this regulation.

## Steam Electric Effluent Limitation Guidelines

The EPA's final steam electric effluent limitation guidelines (ELG) rule took effect in January 2016. Various petitions challenging the rule were consolidated and are pending in the United States Fifth Circuit Court of Appeals. In April 2017, the EPA issued an administrative stay of certain compliance deadlines while further reviewing the rule. In September 2017, the EPA issued a final rule to postpone the earliest compliance dates for the bottom ash transport water and wet flue gas desulfurization wastewater requirements. This rule applies to wastewater discharges from our power plant processes in Wisconsin and Michigan. While the ELG compliance deadlines are postponed, the WDNR and the MDEQ have indicated that they will refrain from incorporating certain new requirements into any reissued discharge permits between 2018 and 2023.

After a final rule is back in effect, the WDNR and MDEQ have indicated that they will modify the state rules as necessary and incorporate the new requirements into our facility permits, which are renewed every five years. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, as currently constructed, the ELG rule will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use.

The final rule would phase in new or more stringent requirements related to limits of arsenic, mercury, selenium, and nitrogen in wastewater discharged from wet scrubber systems. New requirements for wet scrubber wastewater treatment would require additional zero liquid discharge or other advanced treatment capital improvements for the OCPP and ERGS. The rule also would require dry fly ash handling, which is already in place at all of our power plants. Dry bottom ash transport systems are required by the new rule, and modifications would be required at OC 7, OC 8, and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate approximately \$70 million will be required to design and install these advanced treatment and bottom ash transport systems. This estimate reflects the planned retirements of certain of our generation plants as a result of our generation reshaping plan discussed in Climate Change above.

## 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 related to manufactured gas plant sites as of December 31:

| <i>(in millions)</i>            | 2017     | 2016     |
|---------------------------------|----------|----------|
| Regulatory assets               | \$ 676.6 | \$ 702.7 |
| Reserves for future remediation | 617.2    | 633.4    |

## **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 by December 31, 2015. WE and WPS have achieved 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 operating revenues.

### **Michigan Legislation**

In 2008, Michigan enacted Act 295, which required 10% of the state's electric energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. In December 2016, Michigan revised this legislation with Act 342, which requires additional renewable energy requirements beyond 2015. The new legislation retains the 10% renewable energy portfolio requirement for years 2017 through 2018, increases the requirement to 12.5% for years 2019 through 2020, and increases the requirement to 15.0% for 2021. WE and UMERC were in compliance with these requirements as of December 31, 2017. The revised 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 Consent Decree – Weston and Pulliam Power Plants**

In November 2009, the EPA issued a 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.

The final Consent Decree includes:

- the installation of emission control technology, including ReACT™ on Weston 3,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects totaling \$6.0 million, and
- a civil penalty of \$1.2 million.

The Consent Decree also contains requirements to refuel, repower, and/or retire certain Weston and Pulliam units. Effective June 1, 2015, WPS retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved WPS's proposed revision to update requirements reflecting the conversion of Weston Unit 2 from coal to natural gas fuel, and also proposed revisions to the list of beneficial environmental projects required by the Consent Decree. WPS anticipates retirement of the remaining Pulliam units in 2018. See Note 5, Property, Plant, and Equipment, for more information about the retirement.

WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant related to Weston Unit 1 and Pulliam Units 5 and 6 starting June 1, 2015, and concluding by 2023. Therefore, in June 2015, WPS recorded a regulatory asset of \$11.5 million for the undepreciated book value. In addition, WPS received approval from the PSCW in its rate orders to recover prudently incurred costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty.

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

In December 2009, the EPA issued a 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. WE paid an immaterial portion of the assessed penalty but has no further obligations under the Consent Decree.

The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling \$1.3 million, and
- WPS's portion of a civil penalty and legal fees totaling \$0.4 million.

The Consent Decree contains a requirement to, among other things, refuel, repower, or retire Edgewater Unit 4, of which WPS is a joint owner, by no later than December 31, 2018. Management of the joint owners has recommended that Edgewater Unit 4 be retired by September 30, 2018. See Note 5, Property, Plant, and Equipment, for more information about the retirement.

**NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION**

| <i>(in millions)</i>   | 2017       | 2016       | 2015       |
|--|------------|------------|------------|
| Cash (paid) for interest, net of amount capitalized  | \$ (413.7) | \$ (411.9) | \$ (329.6) |
| Cash received (paid) for income taxes, net   | 5.2        | 39.7       | (9.3)      |
| Significant non-cash transactions:   |            |            |            |
| Accounts payable related to construction costs   | 169.2      | 170.1      | 177.1      |
| Increase (decrease) in restricted cash from the sale (purchase) of investments held in the rabbi trust | 4.6        | (59.2)     | (60.2)     |
| Portion of Bostco real estate holdings sale financed with note receivable <sup>(1)</sup>               | 7.0        | —          | —          |
| Amortization of deferred revenue   | 24.9       | 24.7       | 39.9       |
| Note receivable received related to the sale of AMP Trillium LLC <sup>(2)</sup>                        | —          | —          | 12.0       |
| Capital assets received related to the sale of AMP Trillium LLC <sup>(2)</sup>                         | —          | —          | 6.3        |

(1) See Note 3, Dispositions, for more information on this sale.

(2) ITF owned a 30% interest in AMP Trillium LLC. See Note 3, Dispositions, for more information on the sale of ITF.

At December 31, 2017 and 2016, restricted cash of \$19.7 million and \$33.6 million, respectively, was recorded within other long-term assets on our balance sheets. The majority of this amount was held in the Integrys rabbi trust and represents a portion of the required funding that was triggered by the announcement of the Integrys acquisition. Withdrawals of restricted cash from the rabbi trust for qualifying payments are shown as an investing activity on the statements of cash flows. Changes in restricted cash due to the sale or purchase of investments held in the rabbi trust are non-cash transactions and are included in the table above.

**NOTE 23—REGULATORY ENVIRONMENT****Tax Cuts and Jobs Act of 2017**

WEC Energy Group's regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of \$2,450 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes. See Note 13, Income Taxes, for more information.

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

### **2018 and 2019 Rates**

During April 2017, WE, WG, and WPS 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 freezes base rates through 2019 for electric, gas, and steam customers of WE, WG, and WPS. Based on the PSCW order, the authorized ROE for WE, WG, and WPS remains at 10.2%, 10.3%, and 10.0%, respectively, and the current capital cost structure for all of our Wisconsin utilities will remain unchanged through 2019. Various intervenors had filed requests for rehearing, all of which have been denied.

In addition to freezing base rates, the settlement agreement extends and expands the electric real-time market pricing program options for large commercial and industrial customers and mitigates the continued growth of certain escrowed costs at WE during the base rate freeze period by accelerating the recognition of certain tax benefits. The agreement also allows 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. The total cost of the ReACT™ project, excluding \$51 million of AFUDC, is currently estimated to be \$342 million.

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

### **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 the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. The FERC approved the transaction in January 2018. The transaction remains subject to PSCW approval and is expected to close in the spring of 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 would provide approximately one-third of the current storage needs for the natural gas operations of WE, WG, and WPS. As a result of this agreement, WE, WG, and WPS 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, WG, and WPS requested that the PSCW review and confirm the reasonableness and prudence of their potential long-term storage service agreements and interstate natural gas transportation contracts related to the storage facilities. WE, WG, and WPS 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, WG, and WPS 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.

### **2015 Wisconsin Electric Power Company Rate Order**

In May 2014, WE applied to the PSCW for a biennial review of costs and rates. In December 2014, the PSCW approved the following rate adjustments, effective January 1, 2015:

- A net bill increase related to non-fuel costs for WE's retail electric customers of approximately \$2.7 million (0.1%) in 2015. This amount reflected WE's receipt of SSR payments from MISO that were higher than WE anticipated when it filed its rate request in May 2014, as well as an offset of \$26.6 million related to a refund of prior fuel costs and the remainder of the proceeds from a Treasury Grant that WE received in connection with its biomass facility. The majority of this \$26.6 million was returned to customers in the form of bill credits in 2015.
- A rate increase for WE's retail electric customers of \$26.6 million (0.9%) in 2016 related to the expiration of the bill credits provided to customers in 2015.
- A rate decrease of \$13.9 million (-0.5%) in 2015 related to a forecasted decrease in fuel costs.

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- A rate decrease of \$10.7 million (-2.4%) for WE's natural gas customers in 2015, with no rate adjustment in 2016.
- A rate increase of approximately \$0.5 million (2.0%) for WE's Downtown Milwaukee (Valley) steam utility customers in 2015, with no rate adjustment in 2016.
- A rate increase of approximately \$1.2 million (7.3%) for WE's Milwaukee County steam utility customers in 2015, with no rate adjustment in 2016. As a result of the sale of the MCPP, WE no longer has any Milwaukee County steam utility customers. See Note 3, Dispositions, for more information about the sale of the MCPP.

The authorized ROE for WE was set at 10.2%, and its common equity component remained at an average of 51%. The PSCW order reaffirmed the deferral of WE's transmission costs, and it verified that 2015 and 2016 fuel costs should continue to be monitored using a 2% tolerance window. The PSCW order also authorized escrow accounting for SSR revenues because of the uncertainty of the actual revenues WE will receive under the PIPP SSR agreements. Under escrow accounting, WE records SSR revenues of \$90.7 million a year. If actual SSR payments from MISO exceed \$90.7 million a year, the difference is deferred and returned to customers, with interest, in a future rate case. If actual SSR payments from MISO are less than \$90.7 million a year, the difference is deferred and is expected to be recovered from customers with interest, in a future rate case.

### **Earnings Sharing Agreement**

In May 2015, the PSCW approved the acquisition of Integrys subject to the condition of an earnings sharing mechanism for WE. See Note 2, Acquisitions, for more information on this earnings sharing mechanism.

### **2015 Wisconsin Gas Rate Order**

In May 2014, WG applied to the PSCW for a biennial review of costs and rates. In December 2014, the PSCW approved rate increases of \$17.1 million (2.6%) in 2015 and \$21.4 million (3.2%) in 2016 for WG's natural gas customers. These rate adjustments were effective January 1, 2015. The authorized ROE for WG was set at 10.3%. The PSCW also authorized an increase in WG's common equity component to an average of 49.5%.

### **Earnings Sharing Agreement**

In May 2015, the PSCW approved the acquisition of Integrys subject to the condition of an earnings sharing mechanism for WG. See Note 2, Acquisitions, for more information on this earnings sharing mechanism.

### **2016 Wisconsin Public Service Corporation Rate Order**

In April 2015, WPS initiated a rate proceeding with the PSCW. In December 2015, the PSCW issued a final written order for WPS, effective January 1, 2016. The order, which reflects a 10.0% ROE and a common equity component average of 51.0%, authorized a net retail electric rate decrease of \$7.9 million (-0.8%) and a net retail natural gas rate decrease of \$6.2 million (-2.1%). The decrease in retail electric rates was due to lower monitored fuel costs in 2016 compared with 2015. Absent the adjustment for electric fuel costs, WPS would have realized an electric rate increase. Based on the order, the PSCW allowed WPS to escrow ATC and MISO network transmission expenses through 2016. In addition, SSR payments are escrowed until a future rate proceeding. The order directed WPS to defer as a regulatory asset or liability the differences between actual transmission expenses and those included in rates. In addition, the PSCW approved a deferral for ReACT™, which required WPS to defer the revenue requirement of ReACT™ costs above the authorized \$275.0 million level through 2016. Fuel costs will continue to be monitored using a 2% tolerance window.

In March 2016, WPS requested extensions from the PSCW through 2017 for the deferral of the revenue requirement of ReACT™ costs above the authorized \$275.0 million level as well as escrow accounting of ATC and MISO network transmission expenses. In April 2016, WPS also requested to extend through 2017 the previously approved deferral of the revenue requirement difference between the Real Time Market Pricing and the standard tariffed rates for any of WPS's large commercial and industrial customers who entered into a service agreement with WPS under Real Time Market Pricing prior to April 15, 2016. These requests were approved by the PSCW in June 2016.

## **2015 Wisconsin Public Service Corporation Rate Order**

In April 2014, WPS initiated a rate proceeding with the PSCW. In December 2014, the PSCW issued a final written order for WPS, effective January 1, 2015. It authorized a net retail electric rate increase of \$24.6 million and a net retail natural gas rate decrease of \$15.4 million, reflecting a 10.2% ROE. The order authorized a common equity component average of 50.28%. The PSCW approved a change in rate design for WPS, which included higher fixed charges to better match the related fixed costs of providing service. In addition, the order continued to exclude a decoupling mechanism that was terminated beginning January 1, 2014.

The primary driver of the increase in retail electric rates was higher costs of fuel for electric generation of approximately \$42.0 million. In addition, 2015 rates included approximately \$9.0 million of lower refunds to customers related to decoupling over-collections. In addition, WPS received approval from the PSCW to defer and amortize the undepreciated book value associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. See Note 21, Commitments and Contingencies, for more information. The PSCW allowed WPS to escrow ATC and MISO network transmission expenses for 2015 and 2016. As a result, WPS deferred as a regulatory asset the difference between actual transmission expenses and those included in rates until a future rate proceeding. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a 2% tolerance window.

The retail natural gas rate decrease was driven by the approximate \$16.0 million year-over-year negative impact of decoupling refunds to and collections from customers between 2015 and 2014.

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

### **Base Rate Freeze**

In June 2015, the ICC approved the acquisition of Integrys subject to the condition that PGL and NSG will not seek increases of their base rates that would become effective earlier than two years after the close of the acquisition. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or GCRMs.

### **Illinois Proceedings**

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP. This ICC action did not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provided the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops 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. In March 2017, the ICC issued an order directing that additional hearings be held before the ALJ on certain issues to further develop the evidentiary record in the case. This proceeding resulted in a final order issued by the Commission in January 2018. The order did not have a significant impact on PGL's existing SMP design and execution.

### **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 prudence. In March 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. In February 2018, PGL agreed to a settlement of the 2014 reconciliation, which includes a rate base reduction of \$5.4 million and a \$4.7 million refund to ratepayers. As of December 31, 2017, 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.

## **2015 Illinois Rate Order**

In February 2014, PGL and NSG initiated a rate proceeding with the ICC. In January 2015, the ICC issued a final written order for PGL and NSG, effective January 28, 2015. The order authorized a retail natural gas rate increase of \$74.8 million for PGL and \$3.7 million for NSG. In February 2015, the ICC issued an amendatory order that revised the increases to \$71.1 million for PGL and \$3.5 million for NSG, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates for PGL reflected a 9.05% ROE and a common equity component average of 50.33%. The rates for NSG reflected a 9.05% ROE and a common equity component average of 50.48%. The rate order allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, as previously discussed, PGL recovers a return on certain investments and depreciation expense through the QIP rider, and accordingly, such costs are not subject to PGL's rate order.

## **Minnesota Energy Resources Corporation**

### **2018 Minnesota Rate Case**

In October 2017, MERC initiated a rate proceeding with the MPUC to increase retail natural gas rates \$12.6 million (5.05%). MERC's request reflects a 10.3% ROE and a common equity component average of 50.9%. The proposed retail natural gas rate increase is primarily driven by increased capital investments as well as general inflation. MERC is also requesting authority from the MPUC to continue the use of its currently authorized decoupling mechanism.

In November 2017, the MPUC approved an interim rate order, effective January 1, 2018, authorizing a retail natural gas rate increase for MERC of \$9.5 million (3.78%). The interim rates reflect a 9.11% ROE and a common equity component average of 50.9%. The interim rate increase is subject to refund pending the final written rate order, which is expected in the first half of 2019.

### **2016 Minnesota Rate Case**

In September 2015, MERC initiated a rate proceeding with the MPUC. In October 2016, the MPUC issued a final written order for MERC, effective March 1, 2017. The order authorized a retail natural gas rate increase of \$6.8 million (3.0%). The rates reflected a 9.11% ROE and a common equity component average of 50.32%. The order approved MERC's request to continue the use of its decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, we refunded \$4.1 million to MERC's customers in 2017.

### **2015 Minnesota Rate Case**

In September 2013, MERC initiated a rate proceeding with the MPUC. In October 2014, the MPUC issued a final written order for MERC, effective April 1, 2015. The order authorized a retail natural gas rate increase of \$7.6 million. The rates reflected a 9.35% ROE and a common equity component average of 50.31%. The order approved a deferral of customer billing system costs, for which recovery was requested in MERC's 2016 rate case. The order also approved MERC's request to continue the use of its decoupling mechanism with a 10% cap for residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, MERC refunded \$4.7 million to customers in 2015.

## **Michigan Gas Utilities Corporation**

### **2016 Michigan Rate Order**

In June 2015, MGU initiated a rate proceeding with the MPSC. In December 2015, the MPSC issued a final written order approving a settlement agreement for MGU. The order, which reflects a 9.9% ROE and a common equity component average of 52.0%, authorized a retail natural gas rate increase of \$3.4 million (2.4%), effective January 1, 2016. Based on the settlement agreement, MGU discontinued the use of its decoupling mechanism after December 31, 2015. In addition, since bonus depreciation was in effect in 2016, MGU established a regulatory liability for the resulting cost savings and must refund the liability in its next general rate case.

**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 it will 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. The estimated cost of this project is \$266 million (\$277 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. The new units are expected to begin commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. Tilden will remain a customer of WE until this new generation begins commercial operation.

**2015 Rate Order**

In October 2014, WPS initiated a rate proceeding with the MPSC. In April 2015, the MPSC issued a final written order for WPS, effective April 24, 2015, approving a settlement agreement. The order authorized a retail electric rate increase of \$4.0 million to be implemented over three years to recover costs for the 2013 acquisition of the Fox Energy Center as well as other capital investments associated with the Crane Creek wind farm and environmental upgrades at generation plants. The rates reflected a 10.2% ROE and a common equity component average of 50.48%. The increase reflected the continued deferral of costs associated with the Fox Energy Center until the second anniversary of the order. The increase also reflected the deferral of Weston Unit 3 ReACT™ environmental project costs. On the second anniversary of the order, WPS discontinued the deferral of the Fox Energy Center costs and began amortizing this deferral along with the deferral associated with the termination of a tolling agreement related to the Fox Energy Center. WPS also received approval from the MPSC to defer and amortize the undepreciated book value of the retired plant associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. As a result of the formation of UMERC, WPS transferred the deferrals mentioned above, as well as its customers and property, plant, and equipment located in the Upper Peninsula of Michigan to the new utility, effective January 1, 2017. Therefore, the terms and conditions of this rate order were applicable to UMERC starting January 1, 2017.

**NOTE 24—OTHER INCOME, NET**

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

| <i>(in millions)</i>        | 2017           | 2016           | 2015           |
|-----------------------------|----------------|----------------|----------------|
| AFUDC – Equity              | \$ 11.4        | \$ 25.1        | \$ 20.1        |
| Gain on repurchase of notes | —              | 23.6           | —              |
| Gain on asset sales         | 1.9            | 19.6           | 22.9           |
| Other, net                  | 51.3           | 12.5           | 15.9           |
| <b>Other income, net</b>    | <b>\$ 64.6</b> | <b>\$ 80.8</b> | <b>\$ 58.9</b> |

**NOTE 25—QUARTERLY FINANCIAL INFORMATION (Unaudited)**

| <i>(in millions, except per share amounts)</i> | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total      |
|--|---------------|----------------|---------------|----------------|------------|
| <b>2017</b>                                    |               |                |               |                |            |
| Operating revenues                             | \$ 2,304.5    | \$ 1,631.5     | \$ 1,657.5    | \$ 2,055.0     | \$ 7,648.5 |
| Operating income                               | 617.3         | 362.2          | 393.6         | 412.1          | 1,785.2    |
| Net income attributed to common shareholders   | 356.6         | 199.1          | 215.4         | 432.6          | 1,203.7    |
| Earnings per share *                           |               |                |               |                |            |
| Basic  | \$ 1.13       | \$ 0.63        | \$ 0.68       | \$ 1.37        | \$ 3.81    |
| Diluted  | 1.12          | 0.63           | 0.68          | 1.36           | 3.79       |
| <b>2016</b>                                    |               |                |               |                |            |
| Operating revenues                             | \$ 2,194.8    | \$ 1,602.0     | \$ 1,712.5    | \$ 1,963.0     | \$ 7,472.3 |
| Operating income                               | 589.3         | 332.1          | 399.0         | 361.7          | 1,682.1    |
| Net income attributed to common shareholders   | 346.2         | 181.4          | 217.0         | 194.4          | 939.0      |
| Earnings per share *                           |               |                |               |                |            |
| Basic  | \$ 1.10       | \$ 0.57        | \$ 0.69       | \$ 0.62        | \$ 2.98    |
| Diluted  | 1.09          | 0.57           | 0.68          | 0.61           | 2.96       |

\* 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 26—NEW ACCOUNTING PRONOUNCEMENTS**

**Revenue Recognition**

In May 2014, the FASB and the International Accounting Standards Board issued their joint revenue recognition standard, ASU 2014-09, Revenue from Contracts with Customers. Several amendments were issued subsequent to the standard to clarify the guidance. The core principle of the guidance is to recognize revenue in an amount that an entity is entitled to receive in exchange for goods and services. The guidance also requires additional disclosures about the nature, amount, timing, and uncertainty of revenues and the related cash flows arising from contracts with customers.

We have completed the review of our contracts with customers and are finalizing the related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. We have evaluated the nature of our operating revenues and do not expect that there will be a significant shift in the timing or pattern of revenue recognition. Most of our revenues are from tariff sales at our regulated utilities, which are in the scope of the new standard, excluding the revenue component related to alternative revenue programs. The revenues from these contracts are recorded at the amount of the electricity or natural gas delivered to the customer during the period.

We adopted this standard for interim and annual periods beginning January 1, 2018, as required, and used the modified retrospective method of adoption. The most significant impact to the financial statements is expected to be in the form of additional disclosures. However, we do not expect to have a cumulative-effect adjustment to record on the balance sheet as of the beginning of 2018; and therefore, do not expect to include a reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance. We will include disaggregated revenue disclosures by segment, major products (electric and natural gas), and customer class in the combined notes to the financial statements, starting in the first quarter of 2018.

**Recognition and Measurement of Financial Instruments**

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Liabilities. This guidance requires equity investments, including other ownership interests such as partnerships, unincorporated joint ventures, and limited liability companies, to be measured at fair value with changes in fair value recognized in net income. It also simplifies the impairment assessment of equity investments without readily determinable fair values and amends certain disclosure requirements associated with the fair value of financial instruments. This ASU does not apply to investments accounted for under the equity method of accounting. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

## **Leases**

In February 2016, the FASB issued ASU 2016-02, Leases. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, and will be applied using a modified retrospective approach. The main provision of this ASU is that lessees will be required to recognize lease assets and lease liabilities for most leases, including those classified as operating leases under GAAP. We are currently assessing the effects this guidance may have on our financial statements.

## **Financial Instruments Credit Losses**

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. This ASU introduces a new impairment model known as the current expected credit loss model. The ASU requires a financial asset measured at amortized cost to be presented at the net amount expected to be collected. Previously, recognition of the full amount of credit losses was generally delayed until the loss was probable of occurring. We are currently assessing the effects this guidance may have on our financial statements.

## **Classification of Certain Cash Receipts and Cash Payments**

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018 and used a retrospective transition method. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

## **Restricted Cash**

In November 2016, the FASB issued ASU 2016-18, Restricted Cash. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-the period and end-of-the period total amounts shown on the statements of cash flows. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

## **Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost**

In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. Under this ASU, an employer is required to disaggregate the service cost component from the other components of the net benefit cost. The amendments provide explicit guidance on how to present the service cost component and the other components of the net benefit cost in the income statement and allow only the service cost component of the net benefit cost to be eligible for capitalization. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. The amendments will be applied retrospectively for the presentation of the service cost component and the other components of the net benefit cost in the income statement, and prospectively for the capitalization of the service cost component in assets. As a result of the application of accounting principles for rate regulated entities, a similar amount of net benefit cost (including non-service components) will be recognized in our financial statements consistent with the current rate-making treatment. The impacts of adoption will be limited to changes in classification of non-service costs in the income 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, 2017.

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 during the fourth quarter of 2017 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 2019," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance at WEC Energy Group – Stockholder Nominees and Proposals," "Corporate Governance at WEC Energy Group – Board Committees – Independence of the Audit and Oversight, Corporate Governance, and Compensation Committees," and "Committees of the Board of Directors – Audit and Oversight" in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 3, 2018 (the "2018 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" 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](http://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](http://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," "Director Compensation," "Committees of the Board of Directors – Compensation," "Compensation Committee Report," "Pay Ratio Disclosure," "Risk Analysis of Compensation Policies and Practices," and "Certain Relationships and Related Transactions – Compensation Committee Interlocks and Insider Participation" in the 2018 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 2018 Annual Meeting Proxy Statement.

**Equity Compensation Plan Information**

The following table sets forth information about our equity compensation plans as of December 31, 2017:

| Plan Type  | Number of Securities<br>to be Issued<br>Upon Exercise of<br>Outstanding Options,<br>Warrants, and Rights<br>(a) | Weighted Average<br>Exercise Price of<br>Outstanding Options,<br>Warrants, and Rights<br>(b) | Number of Securities<br>Remaining Available for Future<br>Issuance Under Equity<br>Compensation Plans<br>(Excluding Shares Reflected in<br>Column (a))<br>(c) |
|--|---|--|---|
| Equity Compensation Plans Approved by Security Holders     | 4,644,214   | \$ 43.11   | 28,052,421 *  |
| Equity Compensation Plans Not Approved by Security Holders | N/A   | N/A  | N/A   |
| <b>Total</b>   | <b>4,644,214</b>  | <b>\$ 43.11</b>  | <b>28,052,421</b>   |

\* 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 2019 – Director Nominees – Director Independence," "Corporate Governance at WEC Energy Group – Board Independence – Director Independence Standards," "Corporate Governance at WEC Energy Group – Board Committees – Independence of the Audit and Oversight, Corporate Governance, and Compensation Committees," "Corporate Governance at WEC Energy Group – Corporate Governance Framework – Company policies and procedures in place to review and approve related party transactions," and "Certain Relationships and Related Transactions" in the 2018 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 our website, [www.wecenergygroup.com](http://www.wecenergygroup.com).

### **ITEM 14. PRINCIPAL ACCOUNTANT 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 2018 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**

| Description  | Page in 10-K       |
|--|--------------------|
| <a href="#">Reports of Independent Registered Public Accounting Firm.</a>  | <a href="#">73</a> |
| <a href="#">Consolidated Income Statements for the three years ended December 31, 2017, 2016, and 2015.</a>                  | <a href="#">75</a> |
| <a href="#">Consolidated Statements of Comprehensive Income for the three years ended December 31, 2017, 2016, and 2015.</a> | <a href="#">76</a> |
| <a href="#">Consolidated Balance Sheets at December 31, 2017 and 2016.</a>   | <a href="#">77</a> |
| <a href="#">Consolidated Statements of Cash Flows for the three years ended December 31, 2017, 2016, and 2015.</a>           | <a href="#">78</a> |
| <a href="#">Consolidated Statements of Equity for the three years ended December 31, 2017, 2016, and 2015.</a>               | <a href="#">79</a> |
| <a href="#">Consolidated Statements of Capitalization at December 31, 2017 and 2016.</a>                                     | <a href="#">80</a> |
| <a href="#">Notes to Consolidated Financial Statements.</a>  | <a href="#">82</a> |

**2. Financial Statement Schedules Included in Part IV of This Report**

|   |                     |
|---|---------------------|
| <a href="#">Schedule I, Condensed Parent Company Financial Statements, including Income Statements, Statements of Comprehensive Income, and Statements of Cash Flows for the three years ended December 31, 2017, 2016, and 2015 and Balance Sheets as of December 31, 2017 and 2016.</a> | <a href="#">142</a> |
| <a href="#">Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2017, 2016, and 2015.</a>  | <a href="#">148</a> |

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 incorporation by reference pursuant to Exchange Act Rule 12b-32. 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  |
|----------------------|--|
| 2                    | Plan of Acquisition, Reorganization, Arrangement, Liquidation, or Succession   |
| <a href="#">2.1*</a> | <a href="#">Agreement and Plan of Merger, dated as of June 22, 2014, by and between Wisconsin Energy Corporation (n/k/a WEC Energy Group, Inc.) and Integrys Energy Group, Inc. (Exhibit 2.1 to Wisconsin Energy Corporation's 06/22/14 Form 8-K.)</a>       |
| <a href="#">2.2*</a> | <a href="#">Stock Purchase Agreement, dated as of July 29, 2014, between Integrys Energy Group, Inc. and Exelon Generation Company, LLC, as amended on October 31, 2014. (Exhibit 2 under File No. 1-11337, Integrys Energy Group's 09/30/14 Form 10-Q.)</a> |

| Number                | Exhibit  |
|-----------------------|--|
| <b>3</b>              | <b>Articles of Incorporation and By-laws</b>   |
| <a href="#">3.1*</a>  | <a href="#">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.)</a>   |
| <a href="#">3.2*</a>  | <a href="#">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.)</a>  |
| <a href="#">3.3*</a>  | <a href="#">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.)</a>   |
| <b>4</b>              | <b>Instruments defining the rights of security holders, including indentures</b>   |
| <a href="#">4.1*</a>  | Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of WEC Energy Group, Inc. (Exhibits <a href="#">3.1</a> and <a href="#">3.3</a> to WEC Energy Group's 12/31/17 Form 10-K.)   |
| <a href="#">4.2*</a>  | <a href="#">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.)</a>   |
| <a href="#">4.3*</a>  | <a href="#">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.)</a>   |
|                       | <b>Indentures and Securities Resolutions:</b>  |
| <a href="#">4.4*</a>  | <a href="#">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.)</a>  |
| <a href="#">4.5*</a>  | <a href="#">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.)</a>  |
| <a href="#">4.6*</a>  | <a href="#">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.)</a>  |
| <a href="#">4.7*</a>  | <a href="#">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.)</a> |
| <a href="#">4.8*</a>  | <a href="#">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.)</a>   |
| <a href="#">4.9*</a>  | <a href="#">Securities Resolution No. 10 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2009. (Exhibit 4.1 under File No. 1-1245, WE's 12/08/09 Form 8-K.)</a>  |
| <a href="#">4.10*</a> | <a href="#">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.)</a>   |
| <a href="#">4.11*</a> | <a href="#">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.)</a>  |
| <a href="#">4.12*</a> | <a href="#">Securities Resolution No. 13 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of June 10, 2013. (Exhibit 4.1 under File No. 1-1245, WE's 06/10/13 Form 8-K.)</a>   |
| <a href="#">4.13*</a> | <a href="#">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.)</a>  |
| <a href="#">4.14*</a> | <a href="#">Securities Resolution No. 15 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 14, 2015. (Exhibit 4.1 to WE's 05/14/15 Form 8-K.)</a>  |
| <a href="#">4.15*</a> | <a href="#">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.)</a>   |



| <b>Number</b>         | <b>Exhibit</b>  |
|-----------------------|---|
| <a href="#">4.16*</a> | <a href="#">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.)</a>  |
| <a href="#">4.17*</a> | <a href="#">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.)</a>   |
| <a href="#">4.18*</a> | <a href="#">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.)</a>   |
| <a href="#">4.19*</a> | <a href="#">Securities Resolution No. 6 of WEC Energy Group 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.)</a>  |
| <a href="#">4.20*</a> | <a href="#">Indenture, dated as of December 1, 1998, between Wisconsin Public Service Corporation ("WPS") and U.S. Bank National Association (successor to Firststar Bank Milwaukee, N.A., National Association) (Exhibit 4A to Form 8-K filed December 18, 1998) (File No. 1-3016).</a>  |
| <a href="#">4.21*</a> | <a href="#">First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firststar Bank Milwaukee, N.A., National Association (Exhibit 4C to Form 8-K filed December 18, 1998) (File No. 1-3016).</a>  |
| <a href="#">4.22*</a> | <a href="#">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).</a>  |
| <a href="#">4.23*</a> | <a href="#">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).</a>  |
| <a href="#">4.24*</a> | <a href="#">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).</a>  |
| <a href="#">4.25*</a> | <a href="#">Eleventh Supplemental Indenture, dated as of December 4, 2015, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed December 4, 2015) (File No. 1-3016).</a>  |
|                       | <p>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.</p> |
| <b>10</b>             | <b>Material Contracts</b>   |
| <a href="#">10.1*</a> | <a href="#">WEC Energy Group Supplemental Pension Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 12/31/16 Form 10-K.)** See Note.</a>  |
| <a href="#">10.2*</a> | <a href="#">Legacy Wisconsin Energy Corporation Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2016. (Exhibit 10.2 to WEC Energy Group's 12/31/15 Form 10-K.)** See Note.</a>  |
| <a href="#">10.3*</a> | <a href="#">WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.3 to WEC Energy Group's 12/31/16 Form 10-K.)** See Note.</a>   |
| <a href="#">10.4*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.5*</a> | <a href="#">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.)** See Note.</a>  |
| <a href="#">10.6*</a> | <a href="#">WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.6 to WEC Energy Group's 12/31/16 Form 10-K.)** See Note.</a>  |



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| <b>Number</b>          | <b>Exhibit</b>   |
|------------------------|--|
| <a href="#">10.7*</a>  | <a href="#">WEC Energy Group Short-Term Performance Plan, as amended and restated effective as of January 1, 2016. (Exhibit 10.2 to WEC Energy Group's 12/3/15 Form 8-K.)** See Note.</a>  |
| <a href="#">10.8*</a>  | <a href="#">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.)** See Note.</a> |
| <a href="#">10.9*</a>  | <a href="#">Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of December 7, 2017. (Exhibit 10.1 to WEC Energy Group's 12/08/17 Form 8-K.)** See Note.</a>   |
| <a href="#">10.10*</a> | <a href="#">Terms and Conditions Governing Gale Klappa's Restricted Stock Award Under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/08/17 Form 8-K.)** See Note.</a>   |
| <a href="#">10.11*</a> | <a href="#">Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett, dated as of December 30, 2008. (Exhibit 10.26 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.</a>  |
| <a href="#">10.12*</a> | <a href="#">Terms of Employment for J. Patrick Keyes. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/12 Form 10-Q.)** See Note.</a>   |
| <a href="#">10.13*</a> | <a href="#">Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of December 20, 2010. (Exhibit 10.20 to Wisconsin Energy Corporation's 12/31/12 Form 10-K.)** See Note.</a>  |
| <a href="#">10.14*</a> | <a href="#">Amendment to the Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of August 15, 2011. (Exhibit 10.21 to Wisconsin Energy Corporation's 12/31/12 Form 10-K.)** See Note.</a>   |
| <a href="#">10.15*</a> | <a href="#">Terms of Employment for Susan H. Martin. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/12 Form 10-Q.)** See Note.</a>  |
| <a href="#">10.16*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.17*</a> | <a href="#">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.)** See Note.</a>  |
| <a href="#">10.18*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.19</a>  | <a href="#">Consulting Agreement between Wisconsin Energy Corporation and Frederick D. Kuester, dated January 7, 2013 ("Kuester Consulting Agreement").** See Note.</a>  |
| <a href="#">10.20</a>  | <a href="#">Amendment to the Kuester Consulting Agreement, dated January 18, 2018.** See Note.</a>   |
| <a href="#">10.21*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.22*</a> | <a href="#">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.)** See Note.</a>  |
| <a href="#">10.23*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.24*</a> | <a href="#">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.)** See Note.</a>  |
| <a href="#">10.25*</a> | <a href="#">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.)** See Note.</a>  |



| Number                 | Exhibit  |
|------------------------|--|
| <a href="#">10.26*</a> | <a href="#">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.)** See Note.</a>  |
| <a href="#">10.27*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.28*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.29*</a> | <a href="#">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).)</a>  |
| <a href="#">10.30*</a> | <a href="#">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).)</a>   |
| <a href="#">10.31*</a> | <a href="#">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.)</a>  |
| <a href="#">10.32*</a> | <a href="#">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.)</a>   |
| <a href="#">10.33*</a> | <a href="#">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.)</a>   |
| <a href="#">10.34*</a> | <a href="#">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.)</a>  |
| <a href="#">10.35*</a> | <a href="#">Terms and Conditions for July 31, 2015 Special Restricted Stock Award. (Exhibit 10.1 to WEC Energy Group's 6/30/15 Form 10-Q.)** See Note.</a>   |
| <a href="#">10.36*</a> | <a href="#">Integrus 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.)** See Note.</a>  |
| <a href="#">10.37*</a> | <a href="#">Integrus 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.)** See Note.</a>  |
| <a href="#">10.38*</a> | <a href="#">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.)** See Note.</a>   |
| <a href="#">10.39*</a> | <a href="#">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.)** See Note.</a>                           |
| <a href="#">10.40*</a> | <a href="#">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.)** See Note.</a> |
| <b>21</b>              | <b>Subsidiaries of the registrant</b>  |
| <a href="#">21.1</a>   | <a href="#">Subsidiaries of WEC Energy Group.</a>  |
| <b>23</b>              | <b>Consents of experts and counsel</b>   |

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| <b>Number</b> | <b>Exhibit</b>  |
|---------------|---|
|               | <a href="#">23.1 Deloitte &amp; Touche LLP – Milwaukee, WI, Consent of Independent Registered Public Accounting Firm for WEC Energy Group.</a>    |
| <b>31</b>     | <b>Rule 13a-14(a) / 15d-14(a) Certifications</b>  |
|               | <a href="#">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.</a> |
|               | <a href="#">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.</a> |
| <b>32</b>     | <b>Section 1350 Certifications</b>  |
|               | <a href="#">32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</a>      |
|               | <a href="#">32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</a>      |
| <b>101</b>    | <b>Interactive Data File</b>  |

**ITEM 16. FORM 10-K SUMMARY**

None.

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

**A. INCOME STATEMENTS**

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| <b>Year Ended December 31</b>                       |                   |                 |                 |
|---|-------------------|-----------------|-----------------|
| <b>(in millions)</b>                                | <b>2017</b>       | <b>2016</b>     | <b>2015</b>     |
| Operating expenses                                  | \$ 6.0            | \$ 7.0          | \$ 42.2         |
| Equity in earnings of subsidiaries                  | 1,234.7           | 996.5           | 695.7           |
| Other income, net                                   | 2.1               | 2.7             | 23.2            |
| Interest expense                                    | 82.0              | 90.0            | 71.2            |
| Income before income taxes                          | 1,148.8           | 902.2           | 605.5           |
| Income tax benefit                                  | 54.9              | 36.8            | 33.0            |
| <b>Net income attributed to common shareholders</b> | <b>\$ 1,203.7</b> | <b>\$ 939.0</b> | <b>\$ 638.5</b> |

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

**B. STATEMENTS OF COMPREHENSIVE INCOME**

| Year Ended December 31<br>(in millions)  | 2017              | 2016            | 2015            |
|--|-------------------|-----------------|-----------------|
| <b>Net income attributed to common shareholders</b>                                      | <b>\$ 1,203.7</b> | <b>\$ 939.0</b> | <b>\$ 638.5</b> |
| <b>Other comprehensive (loss) income, net of tax</b>                                     |                   |                 |                 |
| <b>Derivatives accounted for as cash flow hedges</b>                                     |                   |                 |                 |
| Gains on settlement, net of tax of \$7.6   | —                 | —               | 11.4            |
| Reclassification of gains to net income, net of tax                                      | (1.3)             | (1.3)           | (0.8)           |
| <b>Cash flow hedges, net</b>   | <b>(1.3)</b>      | <b>(1.3)</b>    | <b>10.6</b>     |
| <b>Defined benefit plans</b>   |                   |                 |                 |
| Pension and OPEB costs arising during the period, net of tax                             | (0.1)             | (1.0)           | (1.5)           |
| Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax | 0.2               | 0.3             | —               |
| <b>Defined benefit plans, net</b>  | <b>0.1</b>        | <b>(0.7)</b>    | <b>(1.5)</b>    |
| <b>Other comprehensive income (loss) from subsidiaries, net of tax</b>                   | <b>1.2</b>        | <b>0.3</b>      | <b>(4.8)</b>    |
| <b>Other comprehensive (loss) income, net of tax</b>                                     | <b>—</b>          | <b>(1.7)</b>    | <b>4.3</b>      |
| <b>Comprehensive income attributed to common shareholders</b>                            | <b>\$ 1,203.7</b> | <b>\$ 937.3</b> | <b>\$ 642.8</b> |

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

**C. BALANCE SHEETS**

| <b>At December 31</b>                    |                    |                    |
|--|--------------------|--------------------|
| <i>(in millions)</i>                     | <b>2017</b>        | <b>2016</b>        |
| <b>Assets</b>                            |                    |                    |
| <b>Current assets</b>                    |                    |                    |
| Cash and cash equivalents                | \$ 4.0             | \$ 1.2             |
| Accounts receivable from related parties | 1.9                | 1.8                |
| Notes receivable from related parties    | 64.1               | 76.4               |
| Prepaid taxes                            | 17.5               | 47.6               |
| Other                                    | 0.6                | 0.5                |
| <b>Current assets</b>                    | <b>88.1</b>        | <b>127.5</b>       |
| <b>Long-term assets</b>                  |                    |                    |
| Investments in subsidiaries              | 12,101.9           | 11,155.4           |
| Note receivable from UMERG               | 50.0               | —                  |
| Other                                    | 47.7               | 134.7              |
| <b>Long-term assets</b>                  | <b>12,199.6</b>    | <b>11,290.1</b>    |
| <b>Total assets</b>                      | <b>\$ 12,287.7</b> | <b>\$ 11,417.6</b> |
| <b>Liabilities and Equity</b>            |                    |                    |
| <b>Current liabilities</b>               |                    |                    |
| Short-term debt                          | \$ 494.8           | \$ 321.8           |
| Current portion of long-term debt        | 300.0              | —                  |
| Accounts payable to related parties      | 2.7                | 3.2                |
| Notes payable to related parties         | 406.0              | 241.3              |
| Other                                    | 8.9                | 10.3               |
| <b>Current liabilities</b>               | <b>1,212.4</b>     | <b>576.6</b>       |
| <b>Long-term liabilities</b>             |                    |                    |
| Long-term debt                           | 1,592.3            | 1,890.0            |
| Other                                    | 21.6               | 21.2               |
| <b>Long-term liabilities</b>             | <b>1,613.9</b>     | <b>1,911.2</b>     |
| Common shareholders' equity              | 9,461.4            | 8,929.8            |
| <b>Total liabilities and equity</b>      | <b>\$ 12,287.7</b> | <b>\$ 11,417.6</b> |

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

**D. STATEMENTS OF CASH FLOWS**

| Year Ended December 31<br>(in millions)                    | 2017           | 2016           | 2015             |
|--|----------------|----------------|------------------|
| <b>Operating activities</b>                                |                |                |                  |
| Net income attributed to common shareholders               | \$ 1,203.7     | \$ 939.0       | \$ 638.5         |
| Reconciliation to cash provided by operating activities    |                |                |                  |
| Equity income in subsidiaries, net of distributions        | (686.1)        | (262.1)        | (156.9)          |
| Deferred income taxes                                      | 89.5           | 23.2           | 30.9             |
| Change in –  |                |                |                  |
| Prepaid taxes  | 28.4           | (47.6)         | —                |
| Other current assets                                       | (0.1)          | 13.0           | (9.3)            |
| Accrued taxes  | —              | (75.6)         | 175.7            |
| Other current liabilities                                  | (1.9)          | (5.6)          | (3.2)            |
| Other, net   | 0.9            | 6.3            | (18.4)           |
| <b>Net cash provided by operating activities</b>           | <b>634.4</b>   | <b>590.6</b>   | <b>657.3</b>     |
| <b>Investing activities</b>                                |                |                |                  |
| Integrus acquisition                                       | —              | —              | (1,486.2)        |
| Bluewater acquisition                                      | (226.0)        | —              | —                |
| Capital contributions to subsidiaries                      | (173.4)        | (55.8)         | (135.3)          |
| Short-term notes receivable from related parties, net      | 167.8          | 46.8           | (91.0)           |
| Issuance of long-term note receivable to UMERG             | (50.0)         | —              | —                |
| Purchase of subsidiary's common stock                      | —              | (66.4)         | —                |
| Proceeds from the sale of assets and businesses            | —              | —              | 20.8             |
| Other, net   | 4.5            | (0.4)          | (0.1)            |
| <b>Net cash used in investing activities</b>               | <b>(277.1)</b> | <b>(75.8)</b>  | <b>(1,691.8)</b> |
| <b>Financing activities</b>                                |                |                |                  |
| Exercise of stock options                                  | 30.8           | 41.6           | 30.1             |
| Purchase of common stock                                   | (71.3)         | (108.0)        | (74.7)           |
| Dividends paid on common stock                             | (656.5)        | (624.9)        | (455.4)          |
| Issuance of long-term debt                                 | —              | —              | 1,200.0          |
| Change in short-term debt                                  | 173.0          | 13.9           | 307.9            |
| Short-term notes payable to related parties, net           | 169.5          | 162.3          | 1.8              |
| Other, net   | —              | 0.2            | (11.2)           |
| <b>Net cash (used in) provided by financing activities</b> | <b>(354.5)</b> | <b>(514.9)</b> | <b>998.5</b>     |
| <b>Net change in cash and cash equivalents</b>             | <b>2.8</b>     | <b>(0.1)</b>   | <b>(36.0)</b>    |
| Cash and cash equivalents at beginning of year             | 1.2            | 1.3            | 37.3             |
| <b>Cash and cash equivalents at end of year</b>            | <b>\$ 4.0</b>  | <b>\$ 1.2</b>  | <b>\$ 1.3</b>    |

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. 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:

| <i>(in millions)</i> | 2017            | 2016            | 2015            |
|----------------------|-----------------|-----------------|-----------------|
| WE                   | \$ 240.0        | \$ 455.0        | \$ 240.0        |
| We Power             | 181.0           | 197.9           | 262.8           |
| ATC Holding LLC      | 82.6            | 6.5             | 6.0             |
| WG                   | 45.0            | 75.0            | 30.0            |
| <b>Total</b>         | <b>\$ 548.6</b> | <b>\$ 734.4</b> | <b>\$ 538.8</b> |

**NOTE 3—LONG-TERM DEBT**

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2017:

| <i>(in millions)</i> |                   |
|----------------------|-------------------|
| 2018                 | \$ 300.0          |
| 2020                 | 400.0             |
| Thereafter           | 1,200.0           |
| <b>Total</b>         | <b>\$ 1,900.0</b> |

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:

| <i>(in millions)</i>                      | 2017            |            | 2016            |            |
|---|-----------------|------------|-----------------|------------|
|   | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term note receivable from UMERG      | \$ 50.0         | \$ 49.5    | \$ —            | \$ —       |
| Long-term debt, including current portion | 1,892.3         | 1,941.5    | 1,890.0         | 1,906.1    |

The carrying value of cash and cash equivalents, accounts receivable, short-term notes receivable, accounts payable, and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our long-term note receivable and long-term debt is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of United States Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. These fair values are categorized within Level 2 of the fair value hierarchy.

**NOTE 5—SUPPLEMENTAL CASH FLOW INFORMATION**

| <i>(in millions)</i>                                | 2017      | 2016      | 2015      |
|---|-----------|-----------|-----------|
| Cash (paid) for interest                            | \$ (82.5) | \$ (89.6) | \$ (68.8) |
| Cash received (paid) for income taxes, net          | 169.9     | (62.9)    | 242.9     |
| <b>Significant non-cash equity transactions</b>     |           |           |           |
| Issuance of short-term note receivable to Bluewater | 115.0     | —         | —         |
| Issuance of short-term note receivable to U MERC    | 40.5      | —         | —         |
| Settlement of short-term note payable with Bostco   | 4.8       | —         | —         |
| Settlement of short-term note payable with Wisvest  | —         | 40.0      | —         |

**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:

| <i>(in millions)</i> | 2017           | 2016           |
|----------------------|----------------|----------------|
| UMERC                | \$ 38.1        | \$ —           |
| Wispark              | 26.0           | 15.9           |
| Integrlys            | —              | 42.0           |
| Bostco               | —              | 18.5           |
| <b>Total</b>         | <b>\$ 64.1</b> | <b>\$ 76.4</b> |

**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:

| <i>(in millions)</i>       | 2017            | 2016            |
|----------------------------|-----------------|-----------------|
| Integrlys                  | \$ 278.2        | \$ —            |
| WECC                       | 110.2           | 109.3           |
| WBS                        | 16.4            | 131.1           |
| Wisvest                    | 0.9             | 0.9             |
| Bluewater Gas Storage, LLC | 0.3             | —               |
| <b>Total</b>               | <b>\$ 406.0</b> | <b>\$ 241.3</b> |

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

| <b>Allowance for Doubtful Accounts<br/>(in millions)</b> | <b>Balance at Beginning of<br/>Period</b> | <b>Acquisitions of<br/>Businesses</b> | <b>Expense (1)</b> | <b>Deferral</b> | <b>Net Write-offs (2)</b> | <b>Balance at End of<br/>Period</b> |
|--|---|---------------------------------------|--------------------|-----------------|---------------------------|-------------------------------------|
| <b>December 31, 2017</b>                                 | \$ 108.0                                  | \$ —                                  | \$ 96.7            | \$ 16.4         | \$ (77.9)                 | \$ 143.2                            |
| December 31, 2016  | 113.3                                     | —                                     | 87.4               | (5.9)           | (86.8)                    | 108.0                               |
| December 31, 2015  | 74.5                                      | 54.3                                  | 56.7               | 8.2             | (80.4)                    | 113.3                               |

(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/ GALE E. KLAPPA

**Date:** February 28, 2018

Gale E. Klappa

Chairman of the Board and Chief Executive Officer

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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.

|   |                   |
|---|-------------------|
| <u>/s/ GALE E. KLAPPA</u><br>Gale E. Klappa, Chairman of the Board, Chief Executive Officer, and<br>Director -- Principal Executive Officer | February 28, 2018 |
| <u>/s/ SCOTT J. LAUBER</u><br>Scott J. Lauber, Executive Vice President and Chief<br>Financial Officer -- Principal Financial Officer       | February 28, 2018 |
| <u>/s/ WILLIAM J. GUC</u><br>William J. Guc, Vice President and<br>Controller -- Principal Accounting Officer                               | February 28, 2018 |
| <u>Allen L. Leverett, President and Director</u>  | February 28, 2018 |
| <u>/s/ JOHN F. BERGSTROM</u><br>John F. Bergstrom, Director   | February 28, 2018 |
| <u>/s/ BARBARA L. BOWLES</u><br>Barbara L. Bowles, Director   | February 28, 2018 |
| <u>/s/ WILLIAM J. BRODSKY</u><br>William J. Brodsky, Director   | February 28, 2018 |
| <u>/s/ ALBERT J. BUDNEY, JR.</u><br>Albert J. Budney, Jr., Director   | February 28, 2018 |
| <u>/s/ PATRICIA W. CHADWICK</u><br>Patricia W. Chadwick, Director   | February 28, 2018 |
| <u>/s/ CURT S. CULVER</u><br>Curt S. Culver, Director   | February 28, 2018 |
| <u>/s/ DANNY L. CUNNINGHAM</u><br>Danny L. Cunningham, Director   | February 28, 2018 |
| <u>/s/ WILLIAM M. FARROW, III</u><br>William M. Farrow, III, Director   | February 28, 2018 |
| <u>/s/ THOMAS J. FISCHER</u><br>Thomas J. Fischer, Director   | February 28, 2018 |
| <u>/s/ HENRY W. KNUEPPEL</u><br>Henry W. Knueppel, Director   | February 28, 2018 |
| <u>/s/ ULICE PAYNE, JR.</u><br>Ulice Payne, Jr., Director   | February 28, 2018 |
| <u>/s/ MARY ELLEN STANEK</u><br>Mary Ellen Stanek, Director   | February 28, 2018 |



CONSULTING AGREEMENT

THIS AGREEMENT is made as of this 7<sup>th</sup> day January, 2013, between WISCONSIN ENERGY CORPORATION, on behalf of itself and its subsidiaries (collectively, the "Company"), and Frederick D. Kuester (the "Consultant").

The Consultant is voluntarily retiring from the employment of the Company as of the close of business on January 4, 2013 (the "Final Retirement Date"). The Consultant has significant experience in the utility industry and considerable knowledge of the Company's generating system, including the construction of major generating facilities. As a result, the Company wishes to obtain the benefits of a consulting agreement ("Agreement") with the Consultant and the Consultant is willing to enter into this Agreement and provide consulting services in accordance with the terms below:

NOW, THEREFORE, in consideration of the terms set forth below, the parties agree as follows:

1. Consulting Services. After the Final Retirement Date, the Consultant agrees to consult with the Company on major construction projects ("Services"). With respect to such Services, the parties agree as follows:
    - (a) The initial term of this Agreement shall commence on January a, 2013, and shall remain in effect for twelve (12) months thereafter, unless terminated by either party pursuant to Paragraph 1(i), below. After the twelve month initial term, this Agreement shall automatically renew on a month to month basis until it is terminated by either party pursuant to Paragraph 1(i), below.
    - (b) The Consultant will be solely responsible for determining the means, manner and method by which he will perform the Services, the times at which those Services will be performed and the sequence of performance of such Services.
    - (c) The Company will pay the Consultant for the consulting services a monthly fee of \$9500.00 dollars for the Services ("Consulting Fee"). The fees specified in this Paragraph 1(c) shall be the sole remuneration paid by the Company to Consultant in exchange for the Services provided by Consultant under this Agreement. Consultant will maintain records for all time spent on the Services. Payment for the Services will be due at the end of each month, upon the Consultant's production of an invoice for the Services. All invoices are to be directed to the Company, to the attention of the Chairman, as follows: Mr. Gale E. Klappa, Chairman, Wisconsin Energy Corporation, Suite P440, 231 West Michigan Street, Milwaukee, Wisconsin 53203.
    - (d) The Consultant will present periodic oral progress reports to the Company on request.
    - (e) The Company will reimburse the Consultant reasonable travel expenses. Consultant shall provide such equipment as shall be necessary to provide the Services.
    - (f) The Consultant is free to perform services for any other person or business during the term of this Agreement provided Consultant does not render services, without the prior
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written approval of the Chairman of the Company, to any other utility, and further provided that such other services do not preclude or conflict with his performance of the Services.

- (g) The Consultant acknowledges that he will not be an employee of the Company or any of its affiliates during the term of this Agreement and that he will not be treated as an employee for federal or state tax purposes, but as an independent contractor. In acknowledging that Consultant is an independent contractor, Consultant agrees that Consultant shall not be entitled to participate in any insurance or other fringe benefits provided by the Company to its active employees and that the Company shall not be required hereunder to withhold nor shall the Company withhold any income, social security, unemployment or other tax or similar payments from the amounts payable to Consultant under this Agreement, it being agreed by Consultant that Consultant shall file all necessary tax returns and pay all necessary taxes consistent with Consultant's status as an independent contractor, and Consultant is liable for any applicable taxes on the amounts earned by Consultant under this Agreement.
  - (h) Services performed under this Agreement will be at the direction of Gale E. Klappa., Chairman, President, and CEO of the Company. The parties agree that Gale E. Klappa has the sole and absolute discretion to determine the scope of the Services. Consultant will not be subject to the direct supervision of the Company. Consultant shall perform all duties that may be required of and from him pursuant to the terms of this Agreement to the reasonable satisfaction of the Company.
  - (i) Either the Company or the Consultant shall have the right at any time and for any reason whatsoever, upon thirty (30) days written notice to the other, to terminate the Agreement. In the event of termination of the Agreement, the Consultant shall be paid for any outstanding Services performed and reasonable travel expenses actually incurred prior to and including the date of termination.
2. Ownership of Documents. All plans, designs, drawings, specifications, calculations, data, information and reports prepared, obtained, developed or furnished to or for the Company in the performance of the Services shall become the sole property of the Company and may not be released, disclosed or published in whole or in part to others without the written permission of the Company.
3. Confidentiality. In order that the Consultant may effectively provide fulfillment of this Agreement to the Company, it may be necessary or desirable for the Company to disclose confidential and proprietary information pertaining to the Company's past, present and future activities. Consultant shall not disclose Confidential Information of the Company to any third party. The foregoing obligation shall not apply to any information that (i) is at the time of disclosure, or thereafter becomes, part of the public domain through no wrongful act or omission of the Consultant, (ii) is subsequently received from a third party having no obligation of confidentiality to the Company, or (iii) is required to be disclosed by lawful order of a court or regulatory body having jurisdiction. For purposes of this Agreement, "Confidential Information" shall mean any confidential or proprietary information of the Company. The confidentiality provisions of this Agreement shall remain in full force and
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effect after the termination of this Agreement.

4. Limited Liability. Consultant will not be liable to the Company for any acts or omissions in the performance of the Services unless such acts or omissions constitute or result from gross negligence or willful misconduct by the Consultant. The Company will indemnify and hold Consultant harmless from any obligations, losses, costs, claims, judgments, damages, and expenses (including reasonable attorneys' fees) arising out of, resulting from, or in any way connected with the Services, unless Consultant is found by a court of competent jurisdiction to have been grossly negligent or to have engaged in willful misconduct. The Company may, at its option and at its own expense, assume the defense as to any such claim.
  5. Entire Agreement, Amendments. This Agreement contains the entire understanding and agreement between the parties with respect to the matters covered and supersedes all other prior agreements and understandings (excepting solely the December 30, 2008 Amended and Restated Senior Officer Employment and Non-Compete Agreement executed between Wisconsin Energy Corporation and Consultant (the "Employment Agreement"), written or oral, between the parties with respect thereto. This Agreement may not be amended except by a written instrument signed by the parties. Nothing contained in this Agreement shall be construed to modify the Employment Agreement or eliminate any obligations under the Employment Agreement.
  6. Notices. Except as otherwise provided above, all communications concerning this Agreement shall be in writing and shall be deemed to have been duly given when delivered or five business days after having been mailed by United States registered or certified mail, return receipt requested, postage prepaid, addressed to the Company to the attention of Susan H. Martin, General Counsel, Wisconsin Energy Corporation, 231 West Michigan Street, Milwaukee, Wisconsin 53203 (telephone 414-221-2712; fax 414-221-2185) and to the Consultant, to the attention of Frederick D. Kuester, [PERSONAL ADDRESS OMITTED] or to such other address as any party may have furnished to the other in writing in accordance herewith, except that notices of a change of address shall be effective only upon receipt.
  7. Waiver. A waiver by the Company of the breach of any of the provisions of this Agreement shall not be deemed to be a waiver by the Company of any subsequent breach. No provision of this Agreement may be waived other than in writing signed by both parties.
  8. Invalidity. The obligations imposed by this Agreement are severable and should be construed independently of each other. The invalidity of one provision shall not affect the validity of any other provision. The parties agree that, should any portion of this Agreement be deemed unreasonable and/or unenforceable, the Agreement shall be construed, and may be modified, to make its terms reasonable, enforceable and applicable to the fullest extent possible consistent with the law.
  9. Severability. Whenever possible, each provision of the Agreement shall be interpreted
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in such a manner as to be effective and valid under applicable law, but if any provision of the Agreement should be prohibited or invalid, in whole or in part, under applicable law, such provisions shall be ineffective only to the extent of such prohibition or invalidity without invalidating the remainder of such provision or the remaining provisions of the Agreement.

IN WITNESS WHEREOF, the parties have signed this Agreement on the date first written above.

WISCONSIN ENERGY CORPORATION

By: /s/ GALE E. KLAPPA                      /s/ FREDERICK D. KUESTER  
Gale E. Klappa                      Frederick D. Kuester  
Chairman, President and CEO

AMENDMENT TO CONSULTING AGREEMENT

This amendment (“Amendment”), dated as of January 18, 2018, amends the Consulting Agreement dated as of January 7, 2013 (“Agreement”), between Wisconsin Energy Corporation, n/k/a WEC Energy Group, Inc. (the “Company”), and Frederick D. Kuester (the “Consultant”). This amendment is entered into by the parties pursuant to Paragraph 5 of the Agreement.

WHEREAS, as a result of recent events at the Company and the Consultant’s significant experience in the utility industry and considerable knowledge of the Company’s business, the Company desires the Consultant to provide additional consulting services than he has been providing under the Agreement; and

WHEREAS, in light of the additional services to be provided by the Consultant to the Company, both parties have agreed to enter into this Amendment.

NOW, THEREFORE, the parties agree as set forth below.

1. The Agreement is hereby amended as follows:

- a. The first sentence of Paragraph 1 is deleted in its entirety and replaced with the following sentence: “The Consultant agrees to consult with the Company on major capital projects and to provide such other services as may be requested by the Company (collectively, the "Services").”
- b. The first sentence of Paragraph 1(c) is amended by deleting “\$9,500” and replacing it with “\$63,750”.
- c. The first sentence of Paragraph 1(h) is deleted in its entirety and replaced with the following sentence “The Services performed under this Agreement will be determined by the CEO of the Company, currently Gale E. Klappa.”

2. Except as specifically amended by this Amendment, the Agreement shall remain in full force and effect. The Agreement and this Amendment shall be read, taken and construed as one and the same instrument.

[Signatures on next page following.]

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IN WITNESS WHEREOF, the parties have signed this Amendment to Consulting Agreement on the date(s) indicated below.

WEC ENERGY GROUP, INC.

By: /s/ GALE E. KLAPPA \_\_\_\_\_ Date: January 18, 2018  
Gale E. Klappa, Chairman and CEO

CONSULTANT

/s/ FREDERICK D. KUESTER \_\_\_\_\_ Date: January 18, 2018  
Frederick D. Kuester

**WEC ENERGY GROUP, INC.**  
**SUBSIDIARIES AS OF DECEMBER 31, 2017**

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, 2017:

| Subsidiary *                                       | State of Incorporation or Organization | Percent Ownership |
|--|--|-------------------|
| <b>Wisconsin Electric Power Company</b>            | Wisconsin                              | 100%              |
| Bostco LLC   | Wisconsin                              | 100%              |
| <b>Wisconsin Gas LLC</b>                           | Wisconsin                              | 100%              |
| <b>ATC Holding LLC</b>                             | Wisconsin                              | 100%              |
| ATC Development Manager, Inc.                      | Delaware                               | 75.17%            |
| ATC Holdco, LLC                                    | Delaware                               | 75.17%            |
| ATC Management Inc.                                | Wisconsin                              | 26.24%            |
| American Transmission Company LLC                  | Wisconsin                              | 26.24%            |
| <b>Bluewater Natural Gas Holding, LLC</b>          | Delaware                               | 100%              |
| Bluewater Gas Storage, LLC                         | Delaware                               | 100%              |
| BGS Kimball Gas Storage, LLC                       | Delaware                               | 100%              |
| <b>W.E. Power, LLC</b>                             | Wisconsin                              | 100%              |
| Elm Road Generating Station Supercritical, LLC     | Wisconsin                              | 100%              |
| Elm Road Services, LLC                             | Wisconsin                              | 100%              |
| Port Washington Generating Station, LLC            | Wisconsin                              | 100%              |
| <b>Wisvest LLC</b>                                 | Wisconsin                              | 100%              |
| <b>Wispark LLC</b>                                 | Wisconsin                              | 100%              |
| <b>Wisconsin Energy Capital Corporation</b>        | Wisconsin                              | 100%              |
| <b>WEC Business Services LLC</b>                   | Delaware                               | 100%              |
| <b>WEC Investments, LLC</b>                        | Delaware                               | 100%              |
| <b>Upper Michigan Energy Resources Corporation</b> | Michigan                               | 100%              |
| <b>Integrys Holding, Inc.</b>                      | Wisconsin                              | 100%              |
| Wisconsin Public Service Corporation               | Wisconsin                              | 100%              |
| Wisconsin Valley Improvement Company               | Wisconsin                              | 27%               |
| Wisconsin River Power Company                      | Wisconsin                              | 50%               |
| WPS Investments, LLC                               | Wisconsin                              | 88%               |
| American Transmission Company LLC                  | Wisconsin                              | 34%               |
| UMERC 2018 Merger Corp.                            | Wisconsin                              | 100%              |
| ATC Management Inc.                                | Wisconsin                              | 34.07%            |
| WPS Investments, LLC                               | Wisconsin                              | 12%               |
| Michigan Gas Utilities Corporation                 | Delaware                               | 100%              |
| Minnesota Energy Resources Corporation             | Delaware                               | 100%              |
| Peoples Energy, LLC                                | Delaware                               | 100%              |
| The Peoples Gas Light and Coke Company             | Illinois                               | 100%              |
| North Shore Gas Company                            | Illinois                               | 100%              |
| Peoples Energy Ventures, LLC                       | Delaware                               | 100%              |
| WPS Power Development, LLC                         | Wisconsin                              | 100%              |
| WPS Visions, Inc.                                  | Wisconsin                              | 100%              |
| Penvest, Inc.                                      | Michigan                               | 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, 2017. 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 333-204556 on Form S-3 and Registration Statement Nos. 333-213589, 333-161151, and 333-177572 on Form S-8 of our reports dated February 28, 2018, 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, 2017.

**/s/DELOITTE & TOUCHE LLP**

Milwaukee, Wisconsin  
February 28, 2018

**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, Gale E. Klappa, 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 28, 2018

/s/ GALE E. KLAPPA

Gale E. Klappa  
Chairman and Chief Executive Officer  
(Principal Executive Officer)

**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 28, 2018

/s/ SCOTT J. LAUBER

Scott J. Lauber  
Executive Vice President and Chief Financial Officer  
(Principal Financial Officer)

**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, 2017, as filed with the Securities and Exchange Commission on February 28, 2018 (the "Report"), I, Gale E. Klappa, Chairman 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/ GALE E. KLAPPA

Gale E. Klappa  
Chairman and Chief Executive Officer  
February 28, 2018

**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, 2017, as filed with the Securities and Exchange Commission on February 28, 2018 (the "Report"), I, Scott J. Lauber, 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

Executive Vice President and Chief Financial Officer

February 28, 2018

