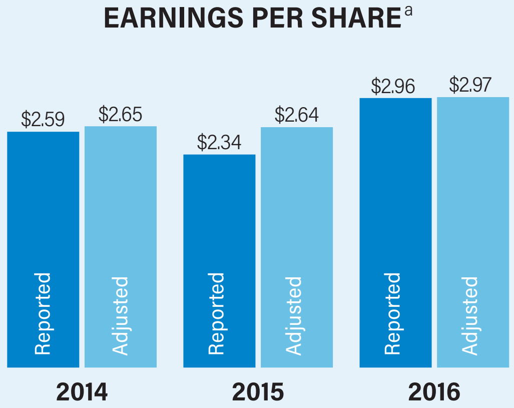
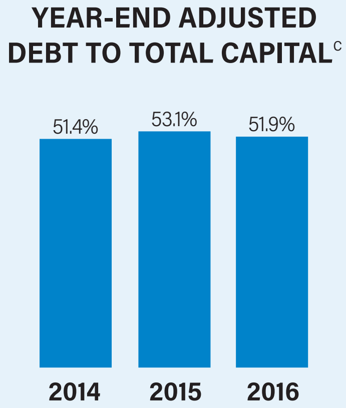
WEC Energy Group

FOCUSED ON THE FUNDAMENTALS

2016 Annual Report

Financial Highlights





a. Adjusted earnings per share exclude acquisition costs totaling 6 cents per share, 30 cents per share and 1 cent per share in 2014, 2015 and 2016, respectively. As a result of the June 29, 2015, acquisition of Integrys, the operations of Integrys are included in both reported and adjusted earnings per share for the last two quarters of 2015 and all of 2016.

b. Annualized based on 4th quarter 2015 dividend of $0.4575.

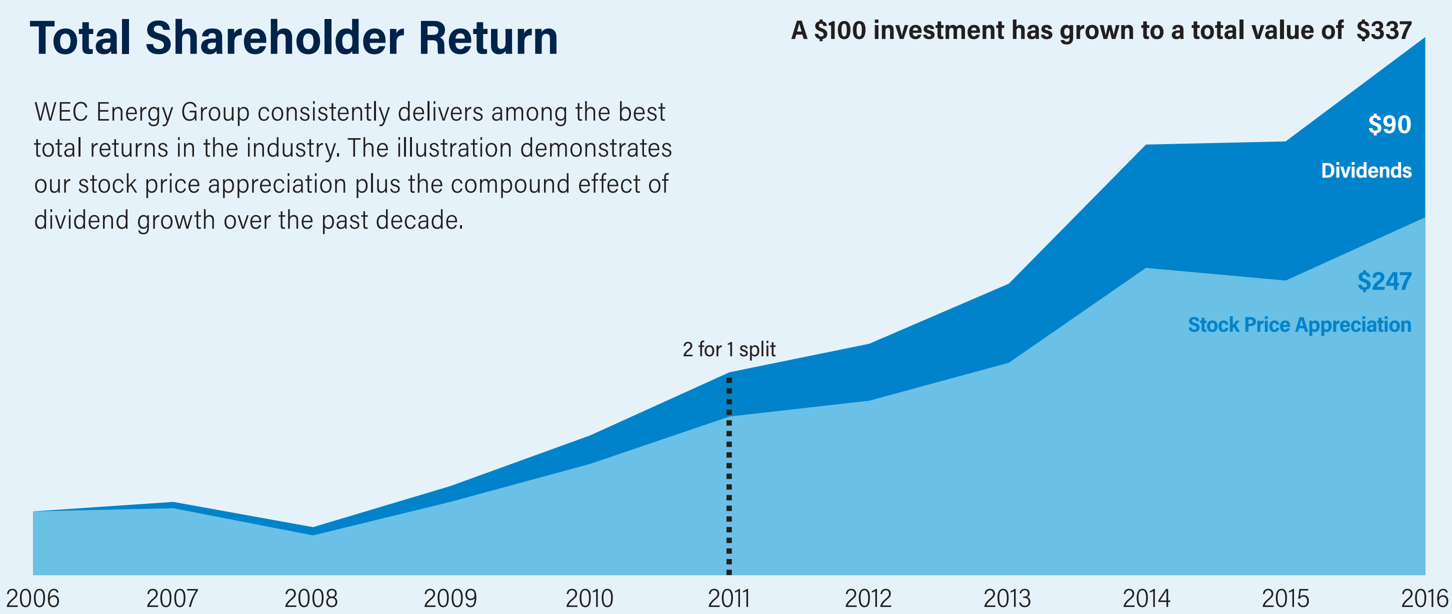
c. Attributes $250 million of 2007 Series A Junior Subordinated Notes to common equity. A majority of the rating agencies currently attribute at least 50% common equity to these securities. For further details, see Capital Resources under Liquidity and Capital Resources in the 2016 annual financial statements.

(Dollars in millions, except per share data and percentages)	2016	2015	% Change
Earnings	$939.0	$638.5	47%
Earnings per share	$2.96	$2.34	26%
Dividends per share	$1.98	$1.83[a]	8%
Dividend yield	3.4%	3.6%	
Diluted average shares outstanding	316.9	272.7	16%
Return on average common equity	10.68%	9.77%	
Book value per share	$28.29	$27.41	3%
Total assets	$30,123	$29,355	3%
Market price per share at year-end	$58.65	$51.31	14%
Market capitalization at year-end	$18,511	$16,198	14%

a. Annualized based on 4th quarter 2015 dividend of $0.4575.

Total Shareholder Return

WEC Energy Group consistently delivers among the best total returns in the industry. The illustration demonstrates our stock price appreciation plus the compound effect of dividend growth over the past decade.



Dear Fellow Shareholder,

This year's annual report theme — "focused on the fundamentals" — underscores the four core principles of our business: safety, efficiency, reliability and financial discipline. We believe that following these principles will make for an enduring franchise.

These principles guide us as we deliver essential services to our customers: electric power, natural gas and, in downtown Milwaukee, steam. All of these are vital to maintaining healthy businesses and also providing comfort and convenience. In many cases, our systems are critical to saving and maintaining the lives of our customers.

One of things I am most pleased about is our continued progress to achieving zero harm to our employees — what we call "Target Zero." In 2016, WEC Energy Group demonstrated significant improvement in its safety performance. Employee participation in proactive safety reporting and in health and wellness programs grew significantly. In addition, the number of OSHA-recordable incidents and lost-time incidents decreased by almost 17 percent on a year-over-year basis.

Our employees work tirelessly to achieve optimal operational results with a customer focus. We Energies, our Milwaukee-based utility, was recognized again for its reliability and customer service in 2016. For the sixth year in a row, We Energies received the ReliabilityOne™ Award for Outstanding Reliability Performance in the Midwest. We Energies also was honored with the Outstanding Customer Reliability Experience Award, underscoring the company's effective customer service and communications.

Our utilities continue to improve the critical infrastructure required to provide service to our customers. These investments will renew and modernize our delivery networks, reduce operating costs, and improve reliability and energy efficiency. Some of the most notable initiatives are as follows.

NEW NATURAL GAS STORAGE

In January, we signed an agreement to acquire Bluewater Natural Gas Holding LLC, an underground

Our utilities continue to improve the critical infrastructure required to provide service to our customers.

natural gas storage facility in Michigan that will provide approximately one-third of the storage needs for our natural gas distribution companies in Wisconsin. The total acquisition price is $230 million.

Bluewater will have three long-term service agreements with our natural gas distribution companies. Under the terms of these agreements, we expect that the risks and returns associated with the investment will be consistent with those that we see in our regulated businesses. In addition, we believe this storage will result in significant savings to our customers over time.

We filed a request with the Public Service Commission of Wisconsin in February for a declaratory ruling to determine if it is reasonable for our Wisconsin natural gas utilities to enter into these transactions. We expect a decision by fall 2017.

IMPROVING RELIABILITY IN NORTHERN WISCONSIN

Wisconsin Public Service is in the process of converting more than 1,000 miles of overhead electric power lines to underground and adding automation equipment on 400 miles of lines to increase reliability for customers. The $220 million project began in 2014 and was scheduled for completion in 2018; however, the project has brought such benefits to customers that we are proposing to expand it to include an additional 900-plus miles. This approximately $200 million extension is scheduled to be completed in 2021.

The four core principles of our business are safety, efficiency, reliability and financial discipline.

MODERNIZING CHICAGO'S NATURAL GAS SYSTEM

Peoples Gas is currently in the early stages of a long-term program to replace approximately 2,000 miles of aging pipelines in Chicago. This will ensure the safe and efficient delivery of natural gas to more than 800,000 customers. In the next three years, we're planning on replacing 250 miles with an investment of approximately $280 million to $300 million annually. The project is more than 20 percent complete.

NEW RENEWABLE GENERATION

In July 2016, the new powerhouse at the Twin Falls hydroelectric facility achieved commercial operation, replacing a powerhouse built in 1912. This project has resulted in large improvements in safety and efficiency. Using the same water flow and pressure, with modern turbine technology, the new powerhouse generates 50 percent more clean, reliable and renewable power than the previous one.

A YEAR OF FINANCIAL ACHIEVEMENT

We are delivering on the promised benefits of the Integrys acquisition completed in June 2015. In fact, our efforts to date have resulted in a nearly 6 percent reduction in operations and maintenance expenses compared to our original target of a reduction of 3 to 5 percent. I believe that, as we continue to streamline and consolidate our systems across the enterprise, we will deliver even more benefits.

Since efficiency and financial discipline go hand-in-hand, we were able to achieve our primary financial goal of earning the allowed return on equity at each of our utilities, while also achieving record earnings per share — growing by more than 8 percent in 2016 over our 2015 stand-alone adjusted earnings per share.

At its January 2017 meeting, our board of directors raised the quarterly dividend on the common stock to 52 cents per share — an increase of 2.5 cents, or 5.1 percent over the previous quarterly dividend level. This represents a compound annual growth rate of 6.6 percent from the 2015 fourth-quarter level. Our annual dividend rate stands at $2.08 per share. The board affirmed our dividend policy that targets a dividend payout ratio of 65 to 70 percent of earnings.

CONTINUING PROGRESS

Looking to the future, I recognize that we need to remain customer-focused and cost-conscious. I also believe that some form of carbon emission regulation is ultimately inevitable. As the regulation of carbon emissions takes shape, our plan is to work with our industry partners, environmental groups and the state of Wisconsin to reduce carbon dioxide emissions by approximately 40 percent below 2005 levels by 2030.

In 2016, about half of the electricity we delivered to our customers was derived from low- or no-carbon sources such as natural gas, nuclear fuel, wind farms and hydroelectric facilities. However, we want to continue to make progress in this area. Relatively flat electricity demand growth, coupled with natural gas and coal economics, have driven us to re-evaluate our generation portfolio. Taken as a group, I want any changes that we make to reduce costs, preserve fuel diversity and keep us on a path to reducing our carbon emissions.

One example of these changes is our proposal to invest approximately $275 million in a 180-MW natural-gas-fueled generation facility in the Upper Peninsula of Michigan. We're targeting commercial operation in 2019, at which time we expect to be in a position to retire our coal-fueled Presque Isle Power Plant. This would significantly reduce operations and maintenance expense as well as carbon dioxide emissions.

IN CONCLUSION

Our employees remain the bedrock of our company. We value, support and develop our colleagues who are making a difference every day in a mission that matters. By keeping employees and customers at the heart of our business, and by working every day to help to grow and support the communities we serve, we believe that we can continue to achieve superior results.

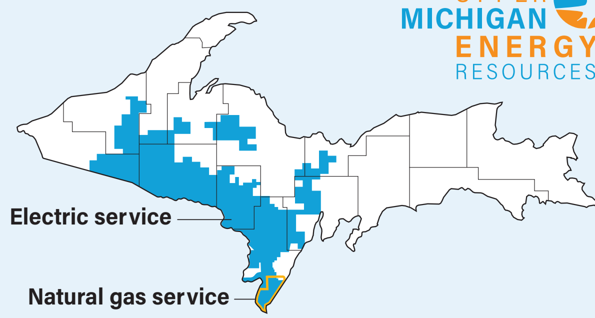
Thank you for your investment in WEC Energy Group,

Allen L. Leverett
President and Chief Executive Officer
March 1, 2017

New utility proposes generation solution for Upper Peninsula of Michigan

Upper Michigan Energy Resources Corp. (UMERC), our stand-alone utility in the Upper Peninsula (U.P.) of Michigan, began operation Jan. 1, 2017.

UPPER MICHIGAN ENERGY RESOURCES



The new utility will help facilitate a future generation solution for the region.

In January, the company filed an application with the Michigan Public Service Commission proposing an estimated $275 million investment in approximately 180 megawatts of natural gas-fueled generation in two locations — Marquette County and Baraga County. The new generation will assure long-term electric reliability in the U.P. and allow for the retirement of the coal-fueled Presque Isle Power Plant.

The proposed facilities would use electric generators called reciprocating internal combustion engines (RICE). These modular engines run on natural gas and allow for reliable and flexible operations.

This technology also provides the following benefits:

- Efficiency is maintained over a wide range of generation output.
- The environmental impact is very low — including limited water use.
- The engines are delivered and installed in modules, sized for the needed capacity.

If approved, construction is planned to begin in late 2017 or early 2018. Commercial operation is planned for 2019.

Building Renewable Generation

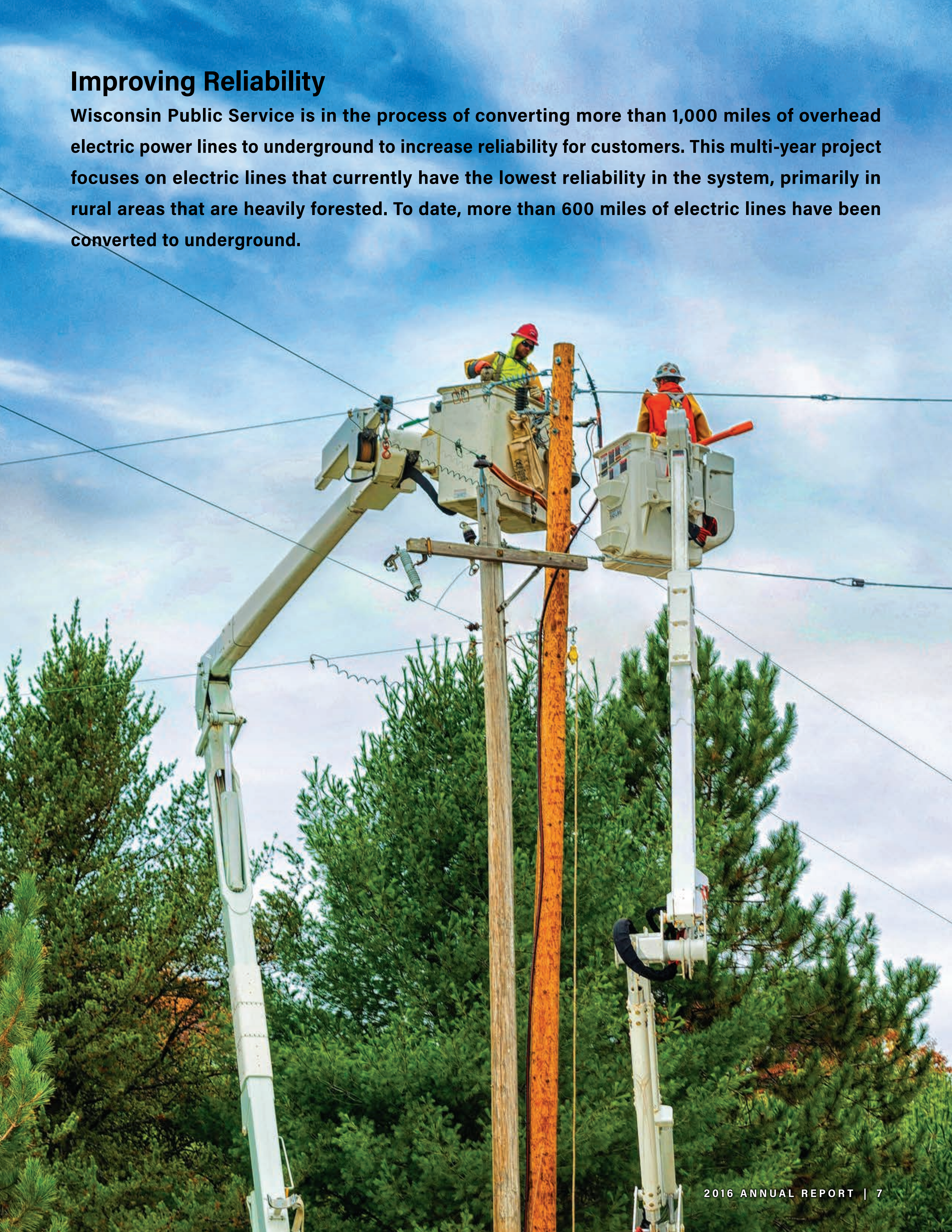
In 2016, the Twin Falls hydroelectric plant began producing clean and reliable renewable energy with a new powerhouse. Built on the Wisconsin side of the Menominee River near the Upper Peninsula of Michigan, it replaces the original powerhouse constructed in 1912. The new facility uses a more efficient turbine technology that has increased the generating capacity by 50 percent and incorporates design features to enhance fish protection.

Upgrading Infrastructure

Peoples Gas has completed more than 20 percent of its program to replace approximately 2,000 miles of natural gas pipelines that serve the city of Chicago. This System Modernization Program removes old cast- and ductile-iron pipes and facilities, some of which date back to the 1860s, and installs modern pipes for long-term system safety and reliability.

Improving Reliability

Wisconsin Public Service is in the process of converting more than 1,000 miles of overhead electric power lines to underground to increase reliability for customers. This multi-year project focuses on electric lines that currently have the lowest reliability in the system, primarily in rural areas that are heavily forested. To date, more than 600 miles of electric lines have been converted to underground.



An Energy Industry Leader

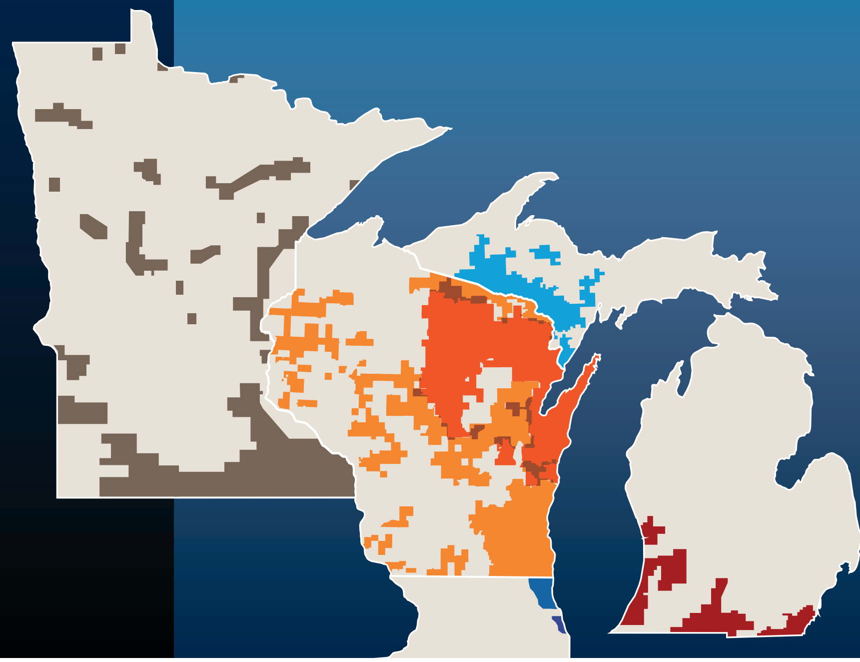
4.4 million
residential, commercial and industrial customers

69,000 miles
of electric distribution

47,000 miles
of natural gas distribution and transmission lines

8,600 megawatts
of power capacity

8,000 employees



WEC Energy Group is one of the nation's largest electric and natural gas delivery companies, with deep operational expertise, scale and financial resources to meet the Midwest region's future energy needs. We provide vital services to nearly 4.4 million customers in Wisconsin, Michigan, Minnesota and Illinois.

In June 2015, WEC Energy Group was formed by Wisconsin Energy Corporation's acquisition of Integrys Energy Group. The acquisition brought together six principal utilities:

- We Energies, delivering electricity, natural gas and steam to more than 2.2 million customers in Wisconsin.
- Wisconsin Public Service, delivering electricity and natural gas to more than 766,000 customers in northeast and central Wisconsin.
- Michigan Gas Utilities, delivering natural gas to more than 174,000 customers in southern and western Michigan.
- Minnesota Energy Resources, delivering natural gas to more than 232,000 customers in communities across Minnesota.
- Peoples Gas, delivering natural gas to more than 843,000 customers in the city of Chicago.
- North Shore Gas, delivering natural gas to more than 159,000 customers in Chicago's northern suburbs.

At the start of 2017, a stand-alone utility was formed to provide electric and natural gas service to more than 41,000 customers previously served by We Energies and Wisconsin Public Service. Upper Michigan Energy Resources Corp. will facilitate a long-term, efficient generation solution in Michigan's Upper Peninsula.

As a Fortune 500 company and the leading energy utility in the Midwest, we are continuing to grow and give back to our communities. The four core principles of our business are safety, efficiency, reliability and financial discipline.

WEC Energy Group

2016 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS

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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
Bostco	Bostco LLC
DATC	Duke-American Transmission Company
ERGSS	Elm Road Generating Station Supercritical, LLC
Integrys	Integrys Holding, Inc. (previously known as Integrys Energy Group, Inc.)
ITF	Integrys 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
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

Environmental Terms

Act 141	2005 Wisconsin Act 141
CAA	Clean Air Act
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
GHG	Greenhouse Gas
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide

Measurements

Dth	Dekatherm (One Dth equals one million Btu)
MDth	One thousand Dekatherms
MW	Megawatt (One MW equals one million Watts)
MWh	Megawatt-hour

Other Terms and Abbreviations

6.11% Junior Notes	Integrys's 2006 6.11% Junior Subordinated Notes Due 2066
ALJ	Administrative Law Judge
ARRs	Auction Revenue Rights
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia
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
MCPP	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
OCPP	Oak Creek Power Plant
OC 5	Oak Creek Power Plant Unit 5
OC 6	Oak Creek Power Plant Unit 6
OC 7	Oak Creek Power Plant Unit 7
OC 8	Oak Creek Power Plant Unit 8
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
ROE	Return on Equity
RTO	Regional Transmission Organization
SMP	Gas System Modernization Program
SMRP	System Modernization and Reliability Project
SSR	System Support Resource
Supreme Court	United States Supreme Court
Treasury Grant	Section 1603 Renewable Energy Treasury Grant
VAPP	Valley Power Plant

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 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, tax law changes, 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;

- 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;

- The risks associated with changing commodity prices, particularly natural gas and electricity, and the availability of sources of fossil fuel, natural gas, purchased power, materials needed to operate environmental controls at our electric generating facilities, or water supply due to high demand, shortages, transportation problems, nonperformance by electric energy or natural gas suppliers under existing power purchase or natural gas supply contracts, or other developments;

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

- 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;

- 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 incidents, the threat of terrorist incidents, and cyber security intrusion, including the failure to maintain the security of personally identifiable information, the associated costs to protect our assets 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 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.

BUSINESS OF THE COMPANY

WEC Energy Group, Inc. was incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys Energy Group and changed its name to WEC Energy Group, Inc. We maintain our principal executive offices in Milwaukee, Wisconsin.

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 our electric and natural gas utility companies, while the term "non-utility" refers to the activities of our electric and natural gas utility companies that are not regulated, as well as We Power. The term "nonregulated" refers to activities at our Corporate and Other Segment.

Our wholly owned subsidiaries are primarily engaged in the business of providing regulated electricity service in Wisconsin and Michigan and regulated natural gas service in Wisconsin, Illinois, Michigan and Minnesota. In addition, we have an approximate 60% equity interest in ATC, an electric transmission company operating mainly in four states. At December 31, 2016, we conducted our operations in the six reportable segments discussed below.

Wisconsin Segment: The Wisconsin segment primarily consists of the electric and natural gas utility and non-utility operations of WE, WG, and WPS, including WE's electric and WPS's electric and natural gas operations in the Upper Peninsula of Michigan that were transferred to UMERC. 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. UMERC became operational effective January 1, 2017, and WE and WPS transferred customers and property, plant, and equipment as of that date.

At December 31, 2016, these companies served approximately 1,596,700 electric customers and 1,437,900 natural gas customers. This segment also includes steam service to approximately 400 WE steam customers in metropolitan Milwaukee, Wisconsin.

Illinois Segment: The Illinois segment consists of the natural gas utility and non-utility operations of PGL and NSG. The approximately 1,003,400 natural gas customers served by PGL and NSG at December 31, 2016, were located in Chicago and the northern suburbs of Chicago. PGL also owns and operates a 38.3 Bcf natural gas storage field in central Illinois.

Other States Segment: The other states segment includes the natural gas utility and non-utility operations of MERC and MGU. These companies served approximately 407,000 natural gas customers at December 31, 2016, with MERC serving customers in various cities and communities throughout Minnesota, and MGU serving customers in the southern portion of lower Michigan.

Electric Transmission Segment: The electric transmission segment includes our approximate 60% ownership interest in ATC, a federally regulated electric transmission company. ATC owns, maintains, monitors, and operates electric transmission systems mainly in Wisconsin, Michigan, Illinois, and Minnesota.

In addition, we own approximately 68% of ATC Holdco, LLC, a separate entity formed in December 2016 to invest in transmission related projects outside of ATC's traditional footprint. As of December 31, 2016, operations were not significant. However, in January 2017, a subsidiary of ATC Holdco and Arizona Electric Power Cooperative entered into a joint operating agreement to develop transmission projects in Arizona and the Southwestern United States.

We Power Segment: We Power, through wholly owned subsidiaries, owns and leases to WE, certain generating facilities. PWGS 1 and PWGS 2, both natural gas-fired generating units, are being leased to WE under long-term leases that run for 25 years. ER 1 and ER 2, both coal-fired generating units, are being leased to WE under long-term leases that run for 30 years.

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, WECC, WBS, PDL, and ITF.

Bostco and Wispark develop and invest in real estate, and combined they had $69.0 million in real estate holdings at December 31, 2016. WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated utilities, as well as certain services to our nonregulated entities. PDL owns distributed renewable solar projects. We completed the sale of ITF, which provided CNG products and services in multiple states, in

February 2016. In April 2016, as part of the sale of WE's Milwaukee County Power Plant, we sold the chilled water generation and distribution assets of Wisvest, which provided chilled water services to the Milwaukee Regional Medical Center.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in ATC (a federally regulated electric transmission company), and non-utility electric operations through our We Power business. See Note 24, Segment Information, for information on our reportable business segments.

CORPORATE STRATEGY

Our goal is to continue to create long-term value for our shareholders and our customers by focusing on the following:

Reliability

We have made significant reliability-related investments in recent years, and plan to continue making significant capital investments to strengthen and modernize the reliability of our generation and distribution networks. Below are a few examples of reliability projects that are currently underway.

- UMERC, our newly created Michigan electric and natural gas utility, is proposing a long-term generation solution for electric reliability in the Upper Peninsula of Michigan. The plan calls for UMERC to construct and operate approximately 180 MW of natural gas-fired generation that will be located in the Upper Peninsula of Michigan. The new generation would provide the region with affordable, reliable electricity that generates less emissions than PIPP. Subject to regulatory approval, the new generation is expected to achieve commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. For more information, see Note 22, Regulatory Environment.

- PGL is continuing to work on its SMP, which primarily involves replacing old cast and ductile iron gas pipes and facilities in the city of Chicago's natural gas delivery system with modern polyethylene pipes to reinforce the long-term safety and reliability of the system.

- WPS continues work on its SMRP, which involves modernizing parts of its electric distribution system by burying or upgrading lines. The project focuses on electric lines that currently have the lowest reliability in its system, primarily in rural areas that are heavily forested. WPS is planning to expand the scope of this project with SMRP Phase II. If approved, SMRP Phase II will address areas of WPS's service territory where reliability is sub-standard to a lesser degree than the areas addressed in the initial phase of the SMRP.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. For example, we received approval from the PSCW to make changes at ERGS to enable the facility to burn coal from the Powder River Basin located in the western United States. The coal 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.

Post merger, we continue to focus on integrating and improving business processes and consolidating our IT infrastructure. We expect the emphasis we are placing on these integration 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, attractive dividends, 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, plant, and 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 acquisition of Integrys and the pending acquisition of a natural gas storage facility in Michigan.

- See Note 3, Dispositions, for information on the sale of ITF and the MCPP.

Our primary investment opportunities are in three areas: our regulated utility business, our investment in ATC, and our generation plants within our We Power segment. Over the next five years, we expect capital contributions to ATC and ATC Holdco to be approximately $350 million. Capital investments 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 $1.4 billion inside the traditional ATC footprint and $300 million outside of the traditional ATC footprint.

Excluding ATC, we expect total capital expenditures for our retail utilities to be approximately $9.7 billion over the next five years. Ongoing projects are discussed in more detail within Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.

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, 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, where employees of our utility subsidiaries contact customers after a completed service call. This program began many years ago at We Energies (the trade name of WE and WG), and is now being rolled out to the Integrys utilities. Customer satisfaction is a priority, and making "We Care" calls is one of the main methods we use to gauge our performance in order to improve customer satisfaction.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our consolidated results:

	Year Ended December 31		
(in millions, except per share data)	**2016**	**2015**	**2014**
Wisconsin	**$ 1,027.0**	$ 884.2	$ 770.2
Illinois	**239.6**	78.1	—
Other states	**49.9**	6.0	—
We Power	**375.6**	373.4	368.0
Corporate and other	**(10.0)**	(91.2)	(26.1)
Total operating income	**1,682.1**	1,250.5	1,112.1
Equity in earnings of transmission affiliate	**146.5**	96.1	66.0
Other income, net	**80.8**	58.9	13.4
Interest expense	**402.7**	331.4	240.3
Income before income taxes	**1,506.7**	1,074.1	951.2
Income tax expense	**566.5**	433.8	361.7
Preferred stock dividends of subsidiary	**1.2**	1.8	1.2
Net income attributed to common shareholders	**$ 939.0**	$ 638.5	$ 588.3
Diluted earnings per share	**$ 2.96**	$ 2.34	$ 2.59

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 Integrys's results for 2016, compared to six months of Integrys's results for 2015. Integrys was acquired on June 29, 2015. See Note 2, Acquisitions, for more information.

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.

2015 Compared with 2014

Earnings increased $50.2 million in 2015, driven by a $30.1 million net increase in earnings due to the inclusion of Integrys's results for the last six months of 2015, partially offset by acquisition costs recorded by us and our subsidiaries. Also contributing to the increase was a $20.8 million pre-tax gain ($12.5 million after tax) from the sale of Minergy LLC and its remaining financial assets in June 2015.

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 report, our Wisconsin operations included operations of WE and WG for all periods, and operations of WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries on June 29, 2015.

	Year Ended December 31		
(in millions)	**2016**	**2015**	**2014**
Electric revenues	**$ 4,628.1**	$ 4,068.5	$ 3,445.2
Fuel and purchased power	**1,473.1**	1,369.3	1,228.1
Total electric margins	**3,155.0**	2,699.2	2,217.1
Natural gas revenues	**1,177.6**	1,122.6	1,496.1
Cost of natural gas sold	**621.2**	640.5	1,036.1
Total natural gas margins	**556.4**	482.1	460.0
Total electric and natural gas margins	**3,711.4**	3,181.3	2,677.1
Other operation and maintenance	**2,025.4**	1,741.0	1,462.7
Depreciation and amortization	**496.6**	408.6	323.2
Property and revenue taxes	**162.4**	147.5	121.0
Operating income	**$ 1,027.0**	$ 884.2	$ 770.2

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

	Year Ended December 31		
(in millions)	**2016**	**2015**	**2014**
Operation and maintenance not included in line items below	**$ 881.9**	$ 744.2	$ 607.4
We Power [(1)]	**513.2**	510.7	462.1
Transmission [(2)]	**423.2**	341.3	278.6
Regulatory amortizations and other pass through expenses [(3)]	**157.4**	144.8	114.6
Earnings sharing mechanisms	**24.4**	—	—
Other	**25.3**	—	—
Total other operation and maintenance	**$ 2,025.4**	$ 1,741.0	$ 1,462.7

(1) Represents costs associated with the We Power generation units, including operating and maintenance, as well as the lease payments that are billed from We Power to WE and then recovered in WE's rates. During 2016, 2015, and 2014, $528.4 million, $483.4 million, and $475.7 million, respectively, of both lease and operating and maintenance costs were billed to WE, with the difference in costs billed and expenses incurred 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 2016, 2015, and 2014, $486.0 million, $388.6 million, and $302.4 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 (in thousands) 2016	2015	2014
Customer class			
Residential	**10,998.9**	9,218.9	7,946.3
Small commercial and industrial *	**13,113.1**	10,889.2	8,843.1
Large commercial and industrial *	**13,418.6**	11,545.8	9,795.3
Other	**172.2**	162.6	148.7
Total retail *	**37,702.8**	31,816.5	26,733.4
Wholesale	**3,704.6**	2,588.1	1,852.8
Resale	**8,761.6**	9,077.1	6,497.9
Total sales in MWh *	**50,169.0**	43,481.7	35,084.1

* 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 (in millions) 2016	2015	2014
Customer class			
Residential	**1,014.9**	859.4	911.5
Commercial and industrial	**610.5**	527.4	571.7
Total retail	**1,625.4**	1,386.8	1,483.2
Transport	**1,270.6**	994.2	838.5
Total sales in therms	**2,896.0**	2,381.0	2,321.7

Weather	Year Ended December 31 Degree Days 2016	2015	2014
WE and WG (1)			
Heating (6,679 normal)	**6,068**	6,468	7,616
Cooling (694 normal)	**991**	622	464
WPS (2)			
Heating (7,498 normal)	**6,715**	2,215	N/A
Cooling (488 normal)	**572**	396	N/A

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

(2) Normal heating and cooling 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.

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.

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 22, 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 utiilty 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 22, 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 (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes). 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 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 in 2016 related to a focus on projects that were beneficial to 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. See the PSCW conditions of approval related to the Integrys acquisition in Note 2, Acquisitions, for more information.

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. See Note 3, Dispositions, for more information.

2015 Compared with 2014

Electric Utility Margins

Electric utility margins at the Wisconsin segment increased $482.1 million during 2015, compared with 2014. The increase was primarily driven by a $399.1 million margin contribution from WPS during the last six months of 2015, compared with no margin contribution from WPS during 2014.

The remaining $83.0 million increase in electric margins at WE was driven by:

- A $38.4 million increase as a result of the PSCW rate order, effective January 1, 2015. See Note 22, Regulatory Environment, for more information.

- A $35.0 million increase driven by the escrow accounting treatment of the SSR revenues in the PSCW rate order, effective January 1, 2015. See Note 22, Regulatory Environment, for more information.

- A $24.2 million increase due to the return of the iron ore mines as customers in February 2015. The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. Effective February 1, 2015, the owner of the two mines returned them as retail customers. In 2015, we deferred, and expect to continue to defer, the margin from those sales and apply these amounts for the benefit of Wisconsin retail electric customers in a future rate proceeding. Michigan state law allows the mines to switch to an alternative electric supplier after sufficient notice. A large portion of this increase in margins was offset by higher transmission expense included in other operation and maintenance expense at WE.

- A $10.4 million positive impact from collections of fuel and purchased power costs compared with costs approved in rates in 2015, compared with 2014. 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.

- A $6.2 million increase primarily due to lower fly ash removal costs in 2015.

- A partially offsetting $22.3 million decrease related to sales volume variances in 2015. This decrease was driven by lower margins from residential customers in 2015, primarily due to lower weather-normalized use per customer and warmer weather during the heating season.

- A partially offsetting $10.8 million decrease in wholesale margins driven by a reduction in sales volumes in 2015.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $22.1 million during 2015, compared with 2014. The increase was related to a $57.9 million margin contribution from WPS during the last six months of 2015, compared with no margin contribution from WPS during 2014. This increase was partially offset by a decrease in natural gas margins at WE and WG of $35.8 million in 2015.

The most significant factor impacting the $35.8 million lower natural gas utility margins at WE and WG was a $42.7 million decrease in sales volumes in 2015, largely related to warmer weather during the heating season as well as lower weather-normalized use per customer. As measured by heating degree days, 2015 was 15.1% warmer than 2014. This decrease in margins was partially offset by a $6.4 million net increase in margins as a result of the impact of the WE and WG PSCW rate orders, effective January 1, 2015. See Note 22, Regulatory Environment, for more information.

Operating Income

Operating income at the Wisconsin segment increased $114.0 million during 2015, compared with 2014. The increase was driven by the $504.2 million increase in margins discussed above, partially offset by $390.2 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes). Higher operating expenses were driven by $334.2 million of operating expenses from WPS during the last six months of 2015, compared with no operating expenses from WPS during 2014.

The significant factors impacting the remaining $56.0 million of higher operating expenses at WE and WG were:

- A $48.6 million increase from higher lease expense related to the We Power leases and associated operating and maintenance expenses as approved in WE's PSCW rate order, effective January 1, 2015.

- A $24.5 million increase in depreciation and amortization expense, driven by:

    - An overall increase in utility plant in service in 2015. 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.

- New depreciation studies approved by the PSCW for both the utilities, effective January 1, 2015.
- A $7.7 million reduction in income received in 2015 from the Treasury Grant WE received in connection with the completion of its biomass plant in November 2013. The lower grant income corresponds to lower bill credits provided to WE's retail electric customers in Wisconsin.

- A $16.0 million increase in transmission expense from MISO and ATC related to the iron ore mines returning as customers in February 2015.
- A combined $6.0 million increase in property and revenues taxes in 2015.

These increases in operating expenses were partially offset by:

- A $16.1 million decrease in employee benefit costs in 2015 driven by lower performance units share-based compensation, deferred compensation, and medical costs.
- A $9.3 million decrease in electric and natural gas distribution costs in 2015, related to amortization of design software and maintenance costs.

ILLINOIS SEGMENT CONTRIBUTION TO OPERATING INCOME

	Year Ended December 31	
(in millions)	**2016**	**2015**
Natural gas revenues	**$ 1,242.2**	$ 503.4
Cost of natural gas sold	**365.2**	133.2
Total natural gas margins	**877.0**	370.2
Other operation and maintenance	**485.1**	219.6
Depreciation and amortization	**134.0**	63.3
Property and revenue taxes	**18.3**	9.2
Operating income	**$ 239.6**	$ 78.1

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

	Year Ended December 31	
(in millions)	**2016**	**2015**
Operation and maintenance not included in the line items below	**$ 385.3**	$ 196.0
Riders *	**82.3**	20.2
Regulatory amortizations *	**2.7**	1.3
Other	**14.8**	2.1
Total other operation and maintenance	**$ 485.1**	$ 219.6

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

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

	Therms *(in millions)*	
Natural Gas Sales Volumes	**2016**	**2015**
Customer Class		
Residential	**905.6**	300.7
Commercial and industrial	**187.6**	63.2
Total retail	**1,093.2**	363.9
Transport	**855.3**	328.4
Total sales in therms	**1,948.5**	692.3

Weather *	Degree Days 2016	Degree Days 2015
Heating (6,154 normal)	**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.

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.

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 included in the table above during the last six months of 2016, compared with the last six months of 2015. PGL and NSG recover certain operating expenses directly through separate riders, resulting in no impact on operating income as increases in operating expenses are offset by equal increases in margins.

- A $10.8 million increase in revenue at PGL due to continued capital investment in projects under its Qualifying Infrastructure Plant rider. PGL currently recovers the costs related to the SMP through a surcharge on customer bills pursuant to an ICC approved Qualifying Infrastructure Plant rider, which is in effect through 2023.

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 included 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 a focus on projects that were beneficial to customers and the communities within our service territory.

OTHER STATES SEGMENT CONTRIBUTION TO OPERATING INCOME

(in millions)	Year Ended December 31 2016	Year Ended December 31 2015
Natural gas revenues	**$ 376.5**	$ 149.3
Cost of natural gas sold	**182.3**	76.9
Total natural gas margins	**194.2**	72.4
Other operation and maintenance	**110.1**	50.0
Depreciation and amortization	**21.1**	10.0
Property and revenue taxes	**13.1**	6.4
Operating income	**$ 49.9**	$ 6.0

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

(in millions)	Year Ended December 31 2016	2015
Operation and maintenance not included in line items below	**$ 86.4**	$ 43.2
Regulatory amortizations and other pass through expenses *	**23.6**	6.7
Other	**0.1**	0.1
Total other operation and maintenance	**$ 110.1**	$ 50.0

* 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 *(in millions)* 2016	2015
Customer Class		
Residential	**278.5**	84.7
Commercial and industrial	**178.2**	60.9
Total retail	**456.7**	145.6
Transport	**696.2**	279.6
Total sales in therms	**1,152.9**	425.2

Weather *	Degree Days 2016	2015
Heating (7,182 normal)	**6,450**	2,193

* 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.

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.

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. The MERC interim rate order 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 to the rate increase. See Note 22, 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 8.2% colder than the last six months of 2015 for these respective territories.

- 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.

WE POWER SEGMENT CONTRIBUTION TO OPERATING INCOME

	Year Ended December 31		
(in millions)	2016	2015	2014
Operating income	**$ 375.6**	$ 373.4	$ 368.0

2016 Compared with 2015

Operating income at the We Power segment increased $2.2 million, or 0.6%, when compared to 2015. This increase was primarily related to higher revenues in connection with capital additions to the plants it owns and leases to WE.

2015 Compared with 2014

Operating income at the We Power segment increased $5.4 million, or 1.5%, when compared to 2014. This increase was primarily related to higher revenues in connection with capital additions to the plants it owns and leases to WE.

CORPORATE AND OTHER SEGMENT CONTRIBUTION TO OPERATING INCOME

	Year Ended December 31		
(in millions)	2016	2015	2014
Operating loss	**$ (10.0)**	$ (91.2)	$ (26.1)

2016 Compared with 2015

The operating loss at the corporate and other segment decreased $81.2 million when compared to 2015, driven by a reduction in costs as a result of the acquisition of Integrys. See Note 2, Acquisitions, for more information regarding costs associated with the acquisition.

2015 Compared with 2014

The operating loss at the corporate and other segment increased $65.1 million when compared to 2014, driven by costs associated with the acquisition of Integrys on June 29, 2015.

ELECTRIC TRANSMISSION SEGMENT OPERATIONS

	Year Ended December 31		
(in millions)	2016	2015	2014
Equity in earnings of transmission affiliate	**$ 146.5**	$ 96.1	$ 66.0

2016 Compared with 2015

Earnings from our ownership interest in ATC increased $50.4 million when compared to 2015, primarily driven by 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, lower equity earnings in 2015 were driven by an ALJ initial decision in December 2015 related to the ATC ROE reviews, which was later affirmed by a FERC order in 2016. See 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 below for more information on these decisions.

2015 Compared with 2014

Earnings from our ownership interest in ATC increased $30.1 million when compared to 2014, primarily driven by the increase in our ownership interest from 26.2% to approximately 60% as a result of the acquisition of Integrys. This increase was partially offset by lower earnings recognized by ATC, as ATC further reduced earnings in 2015 related to an anticipated refund to customers resulting from a complaint filed with the FERC requesting a lower ROE for certain transmission owners.

CONSOLIDATED OTHER INCOME, NET

(in millions)	Year Ended December 31 2016	2015	2014
AFUDC – Equity	**$ 25.1**	$ 20.1	$ 5.6
Gain on repurchase of notes	**23.6**	—	—
Gain on asset sales	**19.6**	22.9	7.5
Other, net	**12.5**	15.9	0.3
Other income, net	**$ 80.8**	$ 58.9	$ 13.4

2016 Compared with 2015

Other income, net increased by $21.9 million when compared to 2015. This increase was primarily due to the repurchase of a portion of Integrys's 6.11% Junior Notes at a discount in February 2016, as well as higher AFUDC due to the inclusion of AFUDC from the Integrys companies post acquisition. See Note 14, Long-Term Debt and Capital Lease Obligations, for more information on the repurchase. Partially offsetting this increase 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. See Note 3, Dispositions, for more information on our asset sales.

2015 Compared with 2014

Other income, net increased by $45.5 million when compared to 2014. This increase was primarily due to the $20.8 million gain from the sale of Minergy LLC and its remaining financial assets in June 2015, as well as higher AFUDC – Equity due to the inclusion of AFUDC from the Integrys companies post acquisition.

CONSOLIDATED INTEREST EXPENSE

(in millions)	Year Ended December 31 2016	2015	2014
Interest expense	**$ 402.7**	$ 331.4	$ 240.3

2016 Compared with 2015

Interest expense increased $71.3 million, or 21.5%, when compared to 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 6.11% Junior Notes in February 2016. These notes were replaced with lower-interest rate short-term debt.

2015 Compared with 2014

Interest expense increased $91.1 million, or 37.9%, when compared to 2014, primarily due to higher debt levels. We assumed approximately $3.0 billion of debt from Integrys and its subsidiaries upon the closing of the acquisition on June 29, 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.

CONSOLIDATED INCOME TAX EXPENSE

	Year Ended December 31		
	2016	**2015**	**2014**
Effective tax rate	**37.6%**	40.4%	38.0%

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. See Note 15, Income Taxes, for more information. We expect our 2017 annual effective tax rate to be between 37.0% and 38.0%.

2015 Compared with 2014

Our effective tax rate was 40.4% in 2015 compared to 38.0% in 2014. This increase in our effective tax rate 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 for the years ended December 31:

(in millions)	2016	2015	2014	Change in 2016 Over 2015	Change in 2015 Over 2014
Cash provided by (used in):					
Operating activities	**$ 2,103.5**	$ 1,293.6	$ 1,198.9	$ 809.9	$ 94.7
Investing activities	**(1,270.1)**	(2,517.5)	(756.8)	1,247.4	(1,760.7)
Financing activities	**(845.7)**	1,211.8	(406.2)	(2,057.5)	1,618.0

Operating Activities

2016 Compared with 2015

Net cash provided by operating activities increased $809.9 million during 2016. 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, 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% in 2016.
- A $94.2 million decrease in contributions and payments to our pension and OPEB plans during 2016.
- A $44.1 million increase in cash due to lower collateral requirements during 2016, driven by an increase in the fair value of our derivative instruments. See Note 20, Derivative Instruments, for more information.
- A $29.2 million increase in cash received for 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.

2015 Compared with 2014

Net cash provided by operating activities increased $94.7 million during 2015, driven by a $141.6 million increase related to net cash flows from the operating activities of Integrys during the last six months of 2015.

The $46.9 million decrease in net cash provided by operating activities from the legacy Wisconsin Energy Corporation companies was driven by:

- A $418.0 million decrease in cash related to lower overall collections from customers during 2015. Collections from customers decreased primarily because of lower commodity prices and warmer weather during the 2015 heating season. The average per-unit cost of natural gas sold decreased 33.1% in 2015.

- A $141.4 million decrease in cash related to higher payments for operating and maintenance costs during 2015, primarily due to costs related to the acquisition of Integrys.

- A $96.8 million increase in contributions and payments to our pension and OPEB plans during 2015.

These decreases in net cash provided by operating activities from the legacy Wisconsin Energy Corporation companies were partially offset by a $592.4 million increase in cash resulting from lower payments for natural gas and fuel and purchased power, due to lower commodity prices and warmer weather during the 2015 heating season.

Investing Activities

2016 Compared with 2015

Net cash used in investing activities decreased $1,247.4 million during 2016, 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 certain assets and businesses during 2016. See Note 3, Dispositions, for more information.

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

- A $157.5 million increase in cash paid for capital expenditures, which is discussed in more detail below.

- A $33.6 million increase in our capital contributions to ATC, 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. See Note 4, Investment in American Transmission Company, for more information.

2015 Compared with 2014

Net cash used in investing activities increased $1,760.7 million during 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.

- A $505.0 million increase in cash paid for capital expenditures during 2015, which is discussed in more detail below.

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

- A $17.3 million increase in cash related to the receipt of the cash surrender value of Integrys corporate-owned life insurance policies in 2015.

- A $15.0 million increase in proceeds from asset sales, driven by the sale of Minergy LLC and its remaining financial assets in 2015.

Capital Expenditures

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

Reportable Segment *(in millions)*	2016	2015	2014	Change in 2016 over 2015	Change in 2015 over 2014
Wisconsin	**$ 910.9**	$ 950.3	$ 715.0	$ (39.4)	$ 235.3
Illinois	**293.2**	194.4	—	98.8	194.4
Other states	**59.5**	34.7	—	24.8	34.7
We Power	**62.3**	53.4	41.0	8.9	12.4
Corporate and other	**97.8**	33.4	5.2	64.4	28.2
Total capital expenditures	**$ 1,423.7**	$ 1,266.2	$ 761.2	$ 157.5	$ 505.0

2016 Compared with 2015

The decrease in cash paid for capital expenditures at the Wisconsin segment during 2016 was driven by lower capital expenditures as a result of 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 ReACT™ emission control technology project at Weston Unit 3, a combustion turbine project at the Fox Energy Center, and the SMRP, a project to underground and upgrade certain electric distribution facilities in northern Wisconsin.

The increase in cash paid for capital expenditures at the Illinois segment during 2016 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 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.

The increase in cash paid for capital expenditures at the corporate and other segment during 2016 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.

See Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements – Capital Expenditures and Significant Capital Projects for more information.

2015 Compared with 2014

The increase in capital expenditures at the Wisconsin segment during 2015 was primarily due to the inclusion of WPS as a result of the Integrys acquisition on June 29, 2015. Significant projects included in WPS's 2015 capital expenditures were the ReACT™ emission control technology project at Weston Unit 3 and the SMRP. The Wisconsin segment also included increased expenditures in 2015 related to WG's Western Gas Lateral project. These increases were partially offset by lower capital expenditures in 2015 for WE's conversion of the fuel source for VAPP from coal to natural gas, as most of the capital expenditures related to this project were incurred in 2014.

The Illinois segment includes capital expenditures from PGL and NSG as a result of the Integrys acquisition on June 29, 2015. In 2015, PGL incurred significant capital expenditures related to the SMP.

The other states segment includes capital expenditures from MERC and MGU as a result of the Integrys acquisition on June 29, 2015.

Financing Activities

2016 Compared with 2015

Net cash related to financing activities decreased $2,057.5 million during 2016, 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, 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 increase in cash used to purchase shares of our common stock during 2016 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.

2015 Compared with 2014

Net cash related to financing activities increased $1,618.0 million during 2015, driven by:

- A $1,900.0 million increase in the issuance of long-term debt during 2015, of which $1,200.0 million related to the acquisition of Integrys.

- An $82.8 million increase in net borrowings of commercial paper during 2015.

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

- A $205.3 million increase in retirements of long-term debt during 2015, of which $130.1 million related to legacy Integrys and its subsidiaries.

- A $103.4 million increase in dividends paid on common stock due to the issuance of 90.2 million shares of our common stock in June 2015 as a result of the Integrys acquisition and an increase in our quarterly dividend rate effective with the closing of the acquisition.

- A $52.7 million decrease 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 13, Short-Term Debt and Lines of Credit, and Note 14, 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 13, 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, 2016 and 2015, as well as an adjusted capitalization structure that we believe is consistent with how the rating agencies currently view our 2007 6.25% Series A Junior Subordinated Notes due 2067 (6.25% Junior Notes):

	2016		2015	
(in millions)	Actual	Adjusted	Actual	Adjusted
Common equity	**$ 8,929.8**	**$ 9,179.8**	$ 8,654.8	$ 8,904.8
Preferred stock of subsidiary	**30.4**	**30.4**	30.4	30.4
Long-term debt (including current maturities)	**9,315.4**	**9,065.4**	9,281.8	9,031.8
Short-term debt	**860.2**	**860.2**	1,095.0	1,095.0
Total capitalization	**$ 19,135.8**	**$ 19,135.8**	$ 19,062.0	$ 19,062.0
Total debt	**$ 10,175.6**	**$ 9,925.6**	$ 10,376.8	$ 10,126.8
Ratio of debt to total capitalization	**53.2%**	**51.9%**	54.4%	53.1%

Included in long-term debt on our balance sheets as of December 31, 2016 and 2015, is $500.0 million principal amount of 6.25% Junior Notes. The adjusted presentation attributes $250.0 million of the 6.25% Junior Notes to common equity and $250.0 million to long-term debt. As a result of Integrys's repurchase and retirement of some of its 6.11% Junior Notes, we were informed by one rating agency that it will no longer attribute equity credit to Integrys's remaining junior subordinated notes, consisting of $114.9 million aggregate principal amount of the 6.11% Junior Notes, and $400.0 million aggregate principal amount of its 6.00% Junior Subordinated Notes due 2073. Therefore, the Integrys junior subordinated notes are no longer being adjusted in the table above. For additional information on the repurchase of the 6.11% Junior Notes, see Note 14, Long-Term Debt and Capital Lease Obligations.

The adjusted presentation of our consolidated capitalization structure is presented 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 6.25% 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 11, 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, 2016, we were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 13, Short-Term Debt and Lines of Credit, for more information about our credit facilities and other short-term credit agreements. See Note 14, Long-Term Debt and Capital Lease Obligations, for more information about our long-term debt.

Working Capital

As of December 31, 2016, our current liabilities exceeded our current assets by approximately $262.9 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 ongoing operations. We also 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.

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.

Capital Requirements

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2016:

	Payments Due by Period (1)				
(in millions)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt obligations (2)	$ 17,658.0	$ 555.3	$ 1,943.2	$ 1,700.4	$ 13,459.1
Capital lease obligations (3)	85.3	13.9	30.2	33.6	7.6
Operating lease obligations (4)	95.5	9.9	14.7	10.8	60.1
Energy and transportation purchase obligations (5)	11,977.5	1,137.7	1,716.2	1,344.7	7,778.9
Purchase orders (6)	1,129.5	721.8	226.5	88.4	92.8
Pension and OPEB funding obligations (7)	170.1	113.3	56.8	—	—
Capital contributions to equity method investments	24.1	24.1	—	—	—
Total contractual obligations	$ 31,140.0	$ 2,576.0	$ 3,987.6	$ 3,177.9	$ 21,398.5

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

(2) Principal and interest payments on long-term debt (excluding capital lease obligations).

(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 2019.

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

AROs in the amount of $557.7 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 for the next three years are as follows:

(in millions)	2017	2018	2019
Wisconsin	$ 1,376.1	$ 1,270.5	$ 1,203.8
Illinois	544.8	517.7	523.4
Other states	91.0	102.7	106.8
We Power	38.4	35.0	36.4
Corporate and other	131.9	30.9	28.9
Total	$ 2,182.2	$ 1,956.8	$ 1,899.3

WPS is continuing work on the SMRP. This project includes converting more than 1,000 miles of overhead distribution power lines to underground in northern Wisconsin and adding distribution automation equipment on 400 miles of lines. WPS expects to invest approximately $45 million annually through 2018. Subject to regulatory review, Phase II of the SMRP will expand the scope and cost of the original SMRP and will consist of over 900 miles of underground circuit installation. WPS expects to invest approximately $200 million between 2018 and 2021 related to Phase II. WE, WPS, and WG will also continue to upgrade their electric and natural gas distribution systems to enhance reliability.

In connection with the formation of UMERC, we entered into an agreement with Tilden Mining Company under which it will purchase electric power from UMERC for 20 years. The agreement calls for UMERC to construct and operate approximately 180 MW of natural gas-fired generation located in the Upper Peninsula of Michigan. The estimated cost of this project is approximately $265 million ($275 million including AFUDC). See Note 22, Regulatory Environment, for more information about UMERC and this new generation.

In January 2017, we signed an agreement for the acquisition of a natural gas storage facility in Michigan for $225 million that would provide approximately one-third of the storage needs for our Wisconsin natural gas utilities. In addition, we expect to incur approximately $5 million of acquisition related costs. See Note 2, Acquisitions, for more information on this transaction.

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 Qualifying Infrastructure Plant rider, which is in effect through 2023. PGL's projected average annual investment through 2019 is between $280 million and $300 million.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $226 million from 2017 through 2019.

Common Stock Matters

For information related to our common stock matters, see Note 11, Common Equity.

On January 19, 2017, our Board of Directors increased our quarterly dividend to $0.52 per share effective with the first quarter of 2017 dividend payment, which equates to an annual dividend of $2.08 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 $3.5 billion as of December 31, 2016. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $28.7 million, $121.0 million, and $13.9 million to our pension and OPEB plans in 2016, 2015, and 2014, respectively. In January 2017, we contributed $100.0 million to the pension plans. 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 13, Short-Term Debt and Lines of Credit, Note 16, Guarantees, and Note 21, 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.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of those costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators. Recovery of these deferred costs in future rates is subject to the review and approval by those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these deferred costs, including those referenced below, is not approved by our regulators, the costs would be charged to income in the current period. In general, our regulatory assets are recovered over a period of between one to 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, 2016, our regulatory assets were $3,138.3 million, and our regulatory liabilities were $1,597.2 million.

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

- In June 2016, the PSCW approved deferral of costs related to WPS's ReACT™ project above the originally authorized $275.0 million level through 2017. WPS will be required to obtain a separate approval for collection of these deferred costs.

- 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, 2016, we had received no 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 Qualifying Infrastructure Plant rider as a recovery mechanism for costs incurred related to investments in qualifying infrastructure plant. This rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. No schedule has been set for the 2015 reconciliation. The ALJ has placed the 2014 reconciliation on a stay, pending resolution of the ICC ordered stakeholder workshops and the ICC investigative docket regarding anonymous letters it received, both related to PGL's SMP. Although schedules have not been set for the reconciliations, discovery has continued for both the 2014 and 2015 reconciliations. As of December 31, 2016, there can be no assurance that all costs incurred under the Qualifying Infrastructure Plant rider will be recoverable.

See Note 22, 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.

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 2016, 2015, and 2014, as measured by degree days, may be found in Management's Discussion and Analysis of Financial Condition and Results of Operations – 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, 2016, and December 31, 2015, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $9.8 million and $11.0 million in 2016 and 2015, respectively. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

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

(in millions)	As of December 31, 2016	Expected Return on Assets in 2017
Pension trust funds	$ 2,709.2	7.11%
OPEB trust funds	$ 773.5	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 fund.

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.

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 retail choice might be implemented, if at all, 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 has been focused on electric reliability infrastructure issues for the state of Wisconsin in recent years. 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. Some of our small retail customers have switched to an alternative electric supplier. As of December 31, 2016, the law limited customer choice to 10% of our Michigan retail load. Due to the December 2016 passage of Michigan Act 341, this cap could potentially be reduced in future years. The iron ore mine in our service territory and certain load increases by facilities already using an alternative electric supplier are excluded from this cap, if various conditions are 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 the natural gas to their facilities, we earn distribution revenues from them. As such, the loss of revenue associated with the natural gas that transportation customers purchase from an alternative retail natural gas supplier has little impact on our net income, since it is offset by an equal reduction to natural gas costs.

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 workably 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 workably 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 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 18, 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 ROEs stated in the ALJ's initial decision, effective as of the order date, on a going-forward basis. The order also requires ATC to provide refunds, with interest, for the 15-month refund period from November 13, 2013, through February 11, 2015. As of December 31, 2016, ATC had started to provide refunds to WE and WPS for transmission costs paid during the refund period, and we expect the refund process to be completed by July 2017. As these refunds are received, WE and WPS reduce the regulatory assets recorded under the PSCW-approved escrow accounting for transmission expense.

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 not certain when a FERC order related to this matter will be issued.

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 will have a negative impact on our equity earnings and distributions from ATC in the future.

Bonus Depreciation Provisions

The Protecting Americans from Tax Hikes Act of 2015 was signed into law on December 18, 2015. This act extended 50% bonus depreciation to assets placed in service during 2015 through 2017, 40% bonus depreciation to assets placed in service during 2018, and 30% bonus depreciation to assets placed in service during 2019. Bonus depreciation is an additional amount of tax deductible depreciation that is awarded above what would normally be available. Due to the resulting increase in federal tax depreciation, we did not make federal income tax payments for 2016, 2015, or 2014.

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, 2016. No impairments were recorded as a result of these tests. For all of our reporting units, the fair value calculated in step one of the test was greater than carrying value. The fair value of each reporting unit was 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 include 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.

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.

The fair values of our reporting units exceeded their carrying values by a substantial amount. 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, 2016:

(in millions, except percentages)	Goodwill	Percentage of Total Goodwill
Wisconsin	$ 2,104.3	69.1%
Illinois	758.7	24.9%
Other states	183.2	6.0%
Total goodwill	$ 3,046.2	100.0%

See Note 10, Goodwill, for more information.

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.

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 ratemaking process.

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

Actuarial Assumption *(in millions, except percentages)*	Percentage-Point Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2016 Pension Cost
Discount rate	(0.5)	$ 202.3	$ 10.4
Discount rate	0.5	(176.1)	(7.4)
Rate of return on plan assets	(0.5)	N/A	13.9
Rate of return on plan assets	0.5	N/A	(13.9)

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

Actuarial Assumption *(in millions, except percentages)*	Percentage-Point Change in Assumption	Impact on Postretirement Benefit Obligation	Impact on 2016 Postretirement Benefit Cost
Discount rate	(0.5)	$ 55.2	$ 2.8
Discount rate	0.5	(47.7)	(2.1)
Health care cost trend rate	(0.5)	34.9	(4.7)
Health care cost trend rate	0.5	40.0	5.4
Rate of return on plan assets	(0.5)	N/A	3.6
Rate of return on plan assets	0.5	N/A	(3.6)

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 7.12% in 2016, 7.37% in 2015, and 7.25% in 2014. The actual rate of return on pension plan assets, net of fees, was 7.75%, (3.85)%, and 6.17%, in 2016, 2015, and 2014, 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 ratemaking 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 as a charge to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. As of December 31, 2016, we had $3,138.3 million in regulatory assets and $1,597.2 million in regulatory liabilities. See Note 6, 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 2016 of approximately $7.4 billion included accrued utility revenues of $509.8 million as of December 31, 2016.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See 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(s), Fair Value Measurements, Note 1(t), Derivative Instruments, and Note 16, Guarantees, for information concerning potential market risks to which we are exposed.

WEC ENERGY GROUP, INC.
CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 ***(in millions, except per share amounts)***	**2016**	**2015**	**2014**
Operating revenues	**$ 7,472.3**	$ 5,926.1	$ 4,997.1
Operating expenses			
Cost of sales	**2,647.4**	2,240.1	2,259.4
Other operation and maintenance	**2,185.5**	1,709.3	1,112.4
Depreciation and amortization	**762.6**	561.8	391.4
Property and revenue taxes	**194.7**	164.4	121.8
Total operating expenses	**5,790.2**	4,675.6	3,885.0
Operating income	**1,682.1**	1,250.5	1,112.1
Equity in earnings of transmission affiliate	**146.5**	96.1	66.0
Other income, net	**80.8**	58.9	13.4
Interest expense	**402.7**	331.4	240.3
Other expense	**(175.4)**	(176.4)	(160.9)
Income before income taxes	**1,506.7**	1,074.1	951.2
Income tax expense	**566.5**	433.8	361.7
Net income	**940.2**	640.3	589.5
Preferred stock dividends of subsidiary	**1.2**	1.8	1.2
Net income attributed to common shareholders	**$ 939.0**	$ 638.5	$ 588.3
Earnings per share			
Basic	**$ 2.98**	$ 2.36	$ 2.61
Diluted	**$ 2.96**	$ 2.34	$ 2.59
Weighted average common shares outstanding			
Basic	**315.6**	271.1	225.6
Diluted	**316.9**	272.7	227.5

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

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2016	2015	2014
Net income	**$ 940.2**	$ 640.3	$ 589.5
Other comprehensive (loss) income, net of tax			
Derivatives accounted for as cash flow hedges			
Gains on settlement, net of tax of $7.6	**—**	11.4	—
Reclassification of gains to net income, net of tax	**(1.3)**	(0.8)	—
Cash flow hedges, net	**(1.3)**	10.6	—
Defined benefit plans			
Pension and OPEB costs arising during the period, net of tax of $0.1 and $(4.2), respectively	**(0.8)**	(6.3)	—
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.4**	—	—
Defined benefit plans, net	**(0.4)**	(6.3)	—
Other comprehensive (loss) income, net of tax	**(1.7)**	4.3	—
Comprehensive income	**938.5**	644.6	589.5
Preferred stock dividends of subsidiary	**1.2**	1.8	1.2
Comprehensive income attributed to common shareholders	**$ 937.3**	$ 642.8	$ 588.3

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WEC ENERGY GROUP, INC.
CONSOLIDATED BALANCE SHEETS

At December 31 ***(in millions, except share and per share amounts)***	**2016**	**2015**
Assets		
Current assets		
Cash and cash equivalents	**$ 37.5**	$ 49.8
Accounts receivable and unbilled revenues, net of reserves of $108.0 and $113.3, respectively	**1,241.7**	1,028.6
Materials, supplies, and inventories	**587.6**	687.0
Assets held for sale	**—**	96.8
Prepayments	**204.4**	285.8
Other	**97.5**	58.8
Current assets	**2,168.7**	2,206.8
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $8,214.6 and $7,919.1, respectively	**19,915.5**	19,189.7
Regulatory assets	**3,087.9**	3,064.6
Equity investment in transmission affiliate	**1,443.9**	1,380.9
Goodwill	**3,046.2**	3,023.5
Other	**461.0**	489.7
Long-term assets	**27,954.5**	27,148.4
Total assets	**$ 30,123.2**	$ 29,355.2
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 860.2**	$ 1,095.0
Current portion of long-term debt	**157.2**	157.7
Accounts payable	**861.5**	815.4
Accrued payroll and benefits	**163.8**	169.7
Other	**388.9**	471.2
Current liabilities	**2,431.6**	2,709.0
Long-term liabilities		
Long-term debt	**9,158.2**	9,124.1
Deferred income taxes	**5,146.6**	4,622.3
Deferred revenue, net	**566.2**	579.4
Regulatory liabilities	**1,563.8**	1,392.2
Environmental remediation liabilities	**633.6**	628.2
Pension and OPEB obligations	**498.6**	543.1
Other	**1,164.4**	1,071.7
Long-term liabilities	**18,731.4**	17,961.0
Commitments and contingencies (Note 18)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,614,941 and 315,683,496 shares outstanding, respectively	**3.2**	3.2
Additional paid in capital	**4,309.8**	4,347.2
Retained earnings	**4,613.9**	4,299.8
Accumulated other comprehensive income	**2.9**	4.6
Common shareholders' equity	**8,929.8**	8,654.8
Preferred stock of subsidiary	**30.4**	30.4
Total liabilities and equity	**$ 30,123.2**	$ 29,355.2

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

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2016	2015	2014
Operating activities			
Net income	**$ 940.2**	$ 640.3	$ 589.5
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**762.6**	583.5	417.0
Deferred income taxes and investment tax credits, net	**493.8**	418.7	328.1
Contributions and payments related to pension and OPEB plans	**(28.7)**	(121.0)	(13.9)
Equity income in transmission affiliate, net of distributions	**(46.6)**	(11.0)	(8.5)
Change in –			
Accounts receivable and unbilled revenues	**(180.7)**	84.0	80.7
Materials, supplies, and inventories	**100.0**	(69.4)	(71.2)
Other current assets	**103.1**	(27.2)	(13.9)
Accounts payable	**34.4**	(9.3)	23.7
Other current liabilities	**(20.8)**	14.1	(45.3)
Other, net	**(53.8)**	(209.1)	(87.3)
Net cash provided by operating activities	**2,103.5**	1,293.6	1,198.9
Investing activities			
Capital expenditures	**(1,423.7)**	(1,266.2)	(761.2)
Business acquisition, net of cash acquired of $156.3	**—**	(1,329.9)	—
Capital contributions to transmission affiliate	**(42.3)**	(8.7)	(13.1)
Proceeds from the sale of assets and businesses	**166.3**	28.9	13.9
Withdrawal of restricted cash from Rabbi trust for qualifying payments	**26.6**	1.4	—
Other, net	**3.0**	57.0	3.6
Net cash used in investing activities	**(1,270.1)**	(2,517.5)	(756.8)
Financing activities			
Exercise of stock options	**41.6**	30.1	50.3
Purchase of common stock	**(108.0)**	(74.7)	(123.2)
Dividends paid on common stock	**(624.9)**	(455.4)	(352.0)
Redemption of WPS preferred stock	**—**	(52.7)	—
Issuance of long-term debt	**400.0**	2,150.0	250.0
Retirement of long-term debt	**(306.0)**	(529.6)	(324.3)
Change in short-term debt	**(234.8)**	163.0	80.2
Other, net	**(13.6)**	(18.9)	12.8
Net cash (used in) provided by financing activities	**(845.7)**	1,211.8	(406.2)
Net change in cash and cash equivalents	**(12.3)**	(12.1)	35.9
Cash and cash equivalents at beginning of year	**49.8**	61.9	26.0
Cash and cash equivalents at end of year	**$ 37.5**	$ 49.8	$ 61.9

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

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	WEC Energy Group Common Shareholders' Equity						
(in millions, expect per share amounts)	**Common Stock**	**Additional Paid-In Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income**	**Total Common Shareholders' Equity**	**Preferred Stock of Subsidiary**	**Total Equity**
Balance at December 31, 2013	$ 2.3	$ 349.7	$ 3,880.7	$ 0.3	$ 4,233.0	$ 30.4	$ 4,263.4
Net income attributed to common shareholders	—	—	588.3	—	588.3	—	588.3
Common stock dividends of $1.56 per share	—	—	(352.0)	—	(352.0)	—	(352.0)
Exercise of stock options	—	50.3	—	—	50.3	—	50.3
Purchase of common stock	—	(123.2)	—	—	(123.2)	—	(123.2)
Stock-based compensation and other	—	23.3	—	—	23.3	—	23.3
Balance at December 31, 2014	$ 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
Balance at December 31, 2015	$ 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 $1.98 per share	**—**	**—**	**(624.9)**	**—**	**(624.9)**	**—**	**(624.9)**
Exercise of stock options	**—**	**41.6**	**—**	**—**	**41.6**	**—**	**41.6**
Purchase of common stock	**—**	**(108.0)**	**—**	**—**	**(108.0)**	**—**	**(108.0)**
Stock-based compensation and other	**—**	**29.0**	**—**	**—**	**29.0**	**—**	**29.0**
Balance at December 31, 2016	**$ 3.2**	**$ 4,309.8**	**$ 4,613.9**	**$ 2.9**	**$ 8,929.8**	**$ 30.4**	**$ 8,960.2**

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

WEC ENERGY GROUP, INC.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2016	2015
Common equity (see accompanying statement)			**$ 8,929.8**	$ 8,654.8
Preferred stock of subsidiary (Note 12)			**30.4**	30.4
Long-term debt	**Interest Rate**	**Year Due**		
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)	6.25%	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 Notes (unsecured)	5.65%	2017	**125.0**	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**	—
PGL First and Refunding Mortgage Bonds (secured) (1)	2.21%	2016	**—**	50.0
	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
	4.30%	2035	**—**	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**	—
	3.65%	2046	**150.0**	—
NSG First Mortgage Bonds (secured) (2)	3.43%	2027	**28.0**	28.0
	3.96%	2043	**54.0**	54.0
We Power Subsidiary Notes (secured, nonrecourse)	4.91% (3)	2017-2030	**106.7**	112.1
	5.209% (4)	2017-2030	**204.8**	215.0
	4.673% (4)	2017-2031	**170.9**	178.3
	6.00% (3)	2017-2033	**126.1**	130.5
	6.09% (4)	2030-2040	**275.0**	275.0
	5.848% (4)	2031-2041	**215.0**	215.0
WECC Notes (unsecured)	6.94%	2028	**50.0**	50.0
Integrys Senior Notes (unsecured)	8.00%	2016	**—**	50.0
	4.17%	2020	**250.0**	250.0
Integrys Junior Notes (unsecured)	3.05% (5)	2066	**114.9**	269.8

Long-term debt (continued)	Interest Rate	Year Due	2016	2015
Integrys Junior Notes (unsecured)	6.00%	2073	**400.0**	400.0
Other Notes (secured, nonrecourse)	4.81%	2030	**2.0**	2.0
Obligations under capital leases			**29.6**	59.9
Total			**9,352.0**	9,314.6
Integrys acquisition fair value adjustment			**33.3**	41.1
Unamortized debt issuance costs			**(38.1)**	(37.8)
Unamortized discount, net and other			**(31.8)**	(36.1)
Total long-term debt, including current portion			**9,315.4**	9,281.8
Current portion of long-term debt and capital lease obligations			**(157.2)**	(157.7)
Total long-term debt			**9,158.2**	9,124.1
Total long-term capitalization			**$ 18,118.4**	$ 17,809.3

(1) 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.

(2) 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.

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

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

(5) Variable interest rate reset quarterly. The rate was 3.05% as of December 31, 2016. Prior to December 1, 2016, fixed rate of 6.11% .

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

WEC ENERGY GROUP, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General Information—On June 29, 2015, Wisconsin Energy Corporation acquired Integrys and changed its name to WEC Energy Group, Inc. WEC Energy Group serves approximately 1.6 million electric customers and 2.8 million natural gas customers, and it owns approximately 60% of ATC. See Note 2, Acquisitions, for more information on this acquisition.

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. WE's electric and WPS's electric and natural gas operations in the state of Michigan are also included in this segment.

- 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.

- We Power segment – Consists of We Power, which is principally engaged in the ownership of electric power generating facilities for long-term lease to WE.

- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, WECC, WBS, PDL, Wisvest and ITF. The sale of ITF was completed in the first quarter of 2016. In the second quarter of 2016, we sold certain assets of Wisvest. 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 8, 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.

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.

(b) Balance Sheet Presentation— To be consistent with the current year presentation, we changed our December 31, 2015 balance sheet from a utility format to a traditional format. This change revised the order of certain balance sheet line items, but it did not result in any change to the classification of amounts between line items.

(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:

- 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 22, 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 22, 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 PGL's natural gas hub and our electric utilities' participation in the MISO Energy Markets. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. 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, 2016. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2016.

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

(in millions)	2016	2015
Natural gas in storage	$ **223.1**	$ 284.1
Materials and supplies	**206.5**	219.2
Fossil fuel	**158.0**	183.7
Total	$ **587.6**	$ 687.0

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 18% of total inventories at December 31, 2016 and 2015. The estimated replacement cost of natural gas in inventory at December 31, 2016 and 2015, exceeded the LIFO cost by $92.9 million and $15.2 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.63 at December 31, 2016, and $2.48 at December 31, 2015.

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 and losses included in earnings related to the investments held at the end of the period were not significant for the years ended December 31, 2016 and 2015.

(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 6, Regulatory Assets and Liabilities, for more information.

(h) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to 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	2016	2015	2014
WE	3.00%	3.01%	2.93%
WPS *	2.58%	1.30%	N/A
WG	2.34%	2.36%	2.69%
PGL *	3.31%	1.67%	N/A
NSG *	2.44%	1.22%	N/A
MERC *	2.53%	1.26%	N/A
MGU *	2.63%	1.32%	N/A

* 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.

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

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

(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 stockholders' 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, and WG. Approximately 50% of WE's, WPS'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 and WBS did not record significant AFUDC for 2016, 2015, or 2014. Average AFUDC rates are shown below:

	2016	
	Average AFUDC Retail Rate	Average AFUDC Wholesale Rate
WE	8.45%	2.73%
WPS	7.72%	3.00%
WG	8.33%	N/A

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

(in millions)	2016	2015	2014
AFUDC – Debt	**$ 10.9**	$ 8.6	$ 2.3
AFUDC – Equity	**$ 25.1**	$ 20.1	$ 5.6

(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. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable.

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.

Due to the acquisition of Integrys, we changed the date of our annual goodwill impairment test from August 31 to July 1. 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 10, Goodwill, 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) 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.

(l) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted to their present values 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 9, Asset Retirement Obligations, for more information.

(m) 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 9, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 18, 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.

(n) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

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

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

(o) 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.

(p) Employee Benefits—The costs of pension and OPEB are expensed over the periods during which employees render service. These costs are allocated 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.

(q) 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 based on our estimate of the final expected value of the awards.

Stock Options

We grant non-qualified stock options that 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.

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 fair value per stock option granted along with the weighted-average assumptions used in the valuation models:

	2016	2015	2014
Non-qualified stock options granted	**794,764**	516,475	899,500
Estimated fair value per non-qualified stock option	**$ 5.14**	$ 5.29	$ 4.18
Assumptions used to value the options:			
Risk-free interest rate	**0.4% – 2.2%**	0.1% – 2.1%	0.1% – 3.0%
Dividend yield	**4.0%**	3.7%	3.8%
Expected volatility	**18.1%**	18.0%	18.0%
Expected life (years)	**6.1**	5.8	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 current dividend rate and historical stock prices. Expected volatility and expected life assumptions were based on our historical experience.

Restricted Shares

Restricted shares have a three-year vesting period, and generally, one-third of the award vests on each 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. All grants are settled in cash and are accounted for as liability awards accordingly. Stock-based compensation costs are recorded over the three-year performance period.

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

(r) 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, 2014.

(s) 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 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 borrowings, 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 19, Fair Value Measurements, for more information.

(t) 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 20, Derivative Instruments, for more information.

(u) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service.

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 current liabilities on our balance sheets.

NOTE 2—ACQUISITIONS

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 holds a 34% interest in ATC, a for-profit transmission company regulated by the FERC. 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:

	Consideration Paid		
(in millions, except per share amounts)	**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
Total purchase price	$ 4,072.9	$ 1,510.2	$ 5,583.1

* 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 FERC. 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 10, 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:

(in millions)	
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)**
Total purchase price	**$ 5,583.1**

* Includes equity method goodwill related to Integrys's investment in ATC. See Note 4, Investment in American Transmission Company, 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 the Western Gas Lateral 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 year ended December 31, 2016, WE and WG recorded a combined $24.4 million of expense related to these earnings sharing mechanisms.

- 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 is currently needed.

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

We do not believe that the conditions set forth in the various regulatory orders approving the acquisition will have a material impact on our operations or financial results.

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.

	Year Ended December 31	
(in millions, except per share amounts)	**2015**	**2014**
Unaudited pro forma financial information		
Operating revenues	$ 7,727.1	$ 9,135.4
Net income attributed to common shareholders	$ 873.5	$ 869.9
Earnings per share (Basic)	$ 2.77	$ 2.76
Earnings per share (Diluted)	$ 2.75	$ 2.74

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 4, Investment in American Transmission Company, for more information.

In connection with the acquisition, WEC Energy Group and its subsidiaries recorded pre-tax acquisition costs of $3.5 million, $107.6 million, and $12.5 million during 2016, 2015, and 2014, 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 during 2016 was not significant. The 2015 severance expense was recorded in the following segments:

(in millions)	**Year ended December 31, 2015**
Wisconsin	$ 11.1
Illinois	0.9
Other states	0.1
Corporate and other	12.8
Total severance expense	$ 24.9

Severance payments of $7.5 million and $16.9 million were made during 2016 and 2015, respectively. The severance accruals on our our balance sheets were not significant at December 31, 2016 and 2015.

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.

Acquisition of a Natural Gas Storage Facility in Michigan

In January 2017, we signed an agreement for the acquisition of a natural gas storage facility in Michigan for $225 million that would provide approximately one-third of the storage needs for our Wisconsin natural gas utilities. In addition, we expect to incur approximately $5 million of acquisition related costs. A request has been filed with the PSCW for a declaratory ruling related to the recovery of this investment. PSCW approval and closing of this transaction are expected to occur by the third quarter of 2017.

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 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 sale of ITF met the criteria to qualify as held for sale at December 31, 2015, but did not meet the requirements to qualify as a discontinued operation. 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.

The following table shows the carrying values of the major classes of assets and liabilities included as held for sale on our balance sheet at December 31:

(in millions)	**2015**
Accounts receivable and unbilled revenues	$ 34.9
Materials, supplies, and inventories	18.4
Other current assets	2.6
Property, plant, and equipment	37.2
Other long-term assets	3.7
Total assets	$ 96.8
Accounts payable	$ 12.9
Accrued payroll and benefits	2.4
Other current liabilities	4.5
Pension and OPEB obligations	1.2
Other long-term liabilities	0.6
Total liabilities *	$ 21.6

* Included in other current liabilities on our balance sheet.

NOTE 4—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

Due to the acquisition of Integrys, our ownership of ATC increased from 26.2% to approximately 60%. ATC is a for-profit, transmission-only company regulated by the FERC and certain state regulatory commissions. We have one representative on ATC's ten-member board of directors. Each member of the board has only one vote. Due to voting requirements, no individual board member has more than 10% of the voting control. The following table shows changes to our investment in ATC during the years ended December 31:

(in millions)	2016	2015	2014
Balance at beginning of period	**$ 1,380.9**	$ 424.1	$ 402.7
Add: Earnings from equity method investment	**146.5**	96.1	66.0
Add: Capital contributions	**42.3**	8.7	13.1
Add: Acquisition of Integrys's investment in ATC	**(1.0)**	541.5	—
Add: Equity method goodwill from the acquisition of Integrys [1]	**10.4**	395.8	—
Less: Distributions	**135.1** [2]	85.1	57.5
Less: Other	**0.1**	0.2	0.2
Balance at end of period	**$ 1,443.9**	$ 1,380.9	$ 424.1

(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 at December 31, 2016.

We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which are reimbursed by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	2016	2015	2014
Charges to ATC for services and construction	**$ 18.5**	$ 15.4	$ 8.1
Charges from ATC for network transmission services	**357.3**	289.2	231.4

As of December 31, 2016 and 2015, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2016	2015
Accounts receivable		
Services provided to ATC	**$ 2.2**	$ 1.0
Accounts payable		
Services received from ATC	**28.7**	28.3

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

(in millions)	2016	2015	2014
Income statement data			
Revenues	**$ 650.8**	$ 615.8	$ 635.0
Operating expenses	**322.5**	319.3	307.4
Other expense	**95.5**	96.1	88.9
Net income	**$ 232.8**	$ 200.4	$ 238.7

(in millions)		December 31, 2016		December 31, 2015
Balance sheet data				
Current assets	**$**	**75.8**	$	80.5
Noncurrent assets		**4,312.9**		3,948.3
Total assets	**$**	**4,388.7**	$	4,028.8
Current liabilities	**$**	**495.1**	$	330.3
Long-term debt		**1,865.3**		1,790.7
Other noncurrent liabilities		**271.5**		245.0
Shareholders' equity		**1,756.8**		1,662.8
Total liabilities and shareholders' equity	**$**	**4,388.7**	$	4,028.8

NOTE 5—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)		2016		2015		2014
Cash (paid) for interest, net of amount capitalized	**$**	**(411.9)**	$	(329.6)	$	(241.4)
Cash received (paid) for income taxes, net		**39.7**		(9.3)		(22.0)
Significant non-cash transactions:						
Accounts payable related to construction costs		**170.1**		177.1		1.8
Restricted cash used to purchase investments held in the rabbi trust		**59.2**		60.2		—
Amortization of deferred revenue		**24.7**		39.9		55.7
Note receivable received related to the sale of AMP Trillium*		**—**		12.0		—
Capital assets received related to the sale of AMP Trillium *		**—**		6.3		—

* ITF owned a 30% interest in AMP. See Note 3, Dispositions, for more information on the sale of ITF.

At December 31, 2016 and 2015, restricted cash of $33.6 million and $118.4 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. Decreases in restricted cash due to the purchase of restricted investments held in the rabbi trust are reflected as non-cash transactions on the statements of cash flows and are included in the table above.

NOTE 6—REGULATORY ASSETS AND LIABILITIES

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

(in millions)		2016		2015	See Note
Regulatory assets (1) (2)					
Unrecognized pension and OPEB costs (3)	**$**	**1,252.1**	$	1,306.4	17
Environmental remediation costs (4)		**702.7**		697.0	18
Income tax related items (5)		**285.1**		248.3	
Electric transmission costs		**234.1**		191.5	22
SSR		**188.1**		86.1	22
AROs		**179.2**		173.0	9
We Power generation (6)		**54.1**		45.4	
Energy efficiency programs (7)		**36.7**		48.7	
Derivatives		**17.9**		70.4	1(t)
Other, net		**188.3**		234.9	
Total regulatory assets	**$**	**3,138.3**	$	3,101.7	
Balance Sheet Presentation					
Current assets (8)	**$**	**50.4**	$	37.1	
Regulatory assets		**3,087.9**		3,064.6	
Total regulatory assets	**$**	**3,138.3**	$	3,101.7	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in the table.

(2) As of December 31, 2016, we had $32.7 million of regulatory assets not earning a return and $204.0 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures.

(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, 2016, we had not yet made cash expenditures for $633.6 million of these environmental remediation costs.

(5) Represents adjustments related to deferred income taxes, which are recovered in rates as the temporary differences that generated the income tax benefit reverse.

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

(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:

(in millions)	2016	2015	See Note
Regulatory liabilities			
Removal costs [1]	**$ 1,262.7**	$ 1,209.6	
Mines deferral [2]	**70.2**	31.6	
Energy costs refundable through rate adjustments [3]	**88.7**	76.9	
Unrecognized pension and OPEB costs [4]	**63.0**	26.3	17
Derivatives	**41.1**	12.6	1(t)
Uncollectible expense [5]	**36.1**	31.8	
Other, net	**35.4**	37.2	
Total regulatory liabilities	**$ 1,597.2**	$ 1,426.0	
Balance Sheet Presentation			
Other current liabilities	**$ 33.4**	$ 33.8	
Regulatory liabilities	**1,563.8**	1,392.2	
Total regulatory liabilities	**$ 1,597.2**	$ 1,426.0	

(1) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.

(2) 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.

(3) Represents energy costs that will be refunded to customers in the future.

(4) 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.

(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 7—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2016	2015
Utility property, plant, and equipment	**$ 24,185.1**	$ 22,803.7
Less: Accumulated depreciation	**7,609.7**	7,358.2
Net	**16,575.4**	15,445.5
CWIP	**320.0**	672.7
Net utility property, plant, and equipment	**16,895.4**	16,118.2
Non-utility and other property, plant, and equipment	**3,520.3**	3,482.2
Less: Accumulated depreciation	**604.9**	560.9
Net	**2,915.4**	2,921.3
CWIP	**104.7**	150.2
Net non-utility and other property, plant, and equipment	**3,020.1**	3,071.5
Total property, plant, and equipment	**$ 19,915.5**	$ 19,189.7

NOTE 8—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 Power and WPS record their 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, 2016 was as follows:

	We Power	WPS		
(in millions, except for percentages and MWs)	Elm Road Generating Station Units 1 and 2	Weston Unit 4	Columbia Energy Center Units 1 and 2 (2)	Edgewater Unit 4
Ownership	**83.34%**	**70.0%**	**31.8%**	**31.8%**
Share of rated capacity (MWs) (1)	**1,056.8**	**373.5**	**334.4**	**98.0**
In-service date	**2010 and 2011**	**2008**	**1975 and 1978**	**1969**
Property, plant, and equipment	**$ 2,430.8**	**$ 596.3**	**$ 417.9**	**$ 45.8**
Accumulated depreciation	**$ (331.5)**	**$ (170.3)**	**$ (128.3)**	**$ (31.7)**
CWIP	**$ 9.4**	**$ 0.2**	**$ 41.2**	**$ 0.1**

(1) Based on expected capacity ratings for summer 2017. 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%.

NOTE 9—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and 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 ratemaking 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.

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

(in millions)	2016	2015	2014
Balance as of January 1	**$ 571.2**	$ 43.6	$ 42.3
Integrys subsidiaries	**—**	491.0	—
Accretion	**28.3**	14.5	2.4
Additions and revisions to estimated cash flows	**—**	35.5 *	—
Liabilities settled	**(41.8)**	(13.4)	(1.1)
Balance as of December 31	**$ 557.7**	$ 571.2	$ 43.6

* 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 10—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, 2016 and 2015:

	Wisconsin		Illinois		Other States		Total	
(in millions)	2016	2015	2016	2015	2016	2015	2016	2015
Goodwill balance as of January 1	**$ 2,109.5**	$ 441.9	**$ 731.2**	$ —	**$ 182.8**	$ —	**$ 3,023.5**	$ 441.9
Adjustment to Integrys purchase price allocation	**(5.2)**	—	**27.5**	—	**0.4**	—	**22.7**	—
Acquisition of Integrys	**—**	1,667.6	**—**	731.2	**—**	182.8	**—**	2,581.6
Goodwill balance as of December 31 *	**$ 2,104.3**	$ 2,109.5	**$ 758.7**	$ 731.2	**$ 183.2**	$ 182.8	**$ 3,046.2**	$ 3,023.5

* We had no accumulated impairment losses related to our goodwill as of December 31, 2016.

Due to the acquisition of Integrys, we changed the date of our annual goodwill impairment test from August 31 to July 1. In the third quarter of 2016, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2016. No impairments resulted from these tests.

NOTE 11—COMMON EQUITY

Stock-Based Compensation Plans

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit for the years ended December 31:

(in millions)	2016	2015	2014
Stock options	**$ 3.5**	$ 3.3	$ 3.7
Restricted stock	**5.8**	7.0	2.8
Performance units	**8.7**	13.0	15.4
Stock-based compensation expense	**$ 18.0**	$ 23.3	$ 21.9
Related tax benefit	**$ 7.2**	$ 9.3	$ 8.8

Stock-based compensation costs capitalized during 2016, 2015, and 2014 were not significant.

Stock Options

The following is a summary of our stock option activity during 2016:

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, 2016	5,984,664	$ 33.47		
Granted	**794,764**	**$ 52.15**		
Exercised	**(1,644,353)**	**$ 25.30**		
Forfeited	**(12,300)**	**$ 52.98**		
Outstanding as of December 31, 2016	**5,122,775**	**$ 38.95**	**6.0**	**$ 100.9**
Exercisable as of December 31, 2016	**3,710,836**	**$ 35.38**	**5.2**	**$ 86.4**

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, 2016. This is calculated as the difference between our closing stock price on December 31, 2016, 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, 2016, 2015, and 2014 was $55.4 million, $36.1 million, and $50.5 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $22.2 million, $14.5 million, and $19.9 million, respectively.

As of December 31, 2016, the total unrecognized compensation cost related to unvested stock options was not significant.

During the first quarter of 2017, the Compensation Committee awarded 552,215 non-qualified stock options with a weighted-average exercise price of $58.31 and a weighted-average grant date fair value of $7.45 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 2016:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2016	229,018	$ 46.78
Granted	**146,941**	**$ 53.69**
Released	**(141,224)**	**$ 46.14**
Forfeited	**(14,689)**	**$ 54.39**
Outstanding as of December 31, 2016	**220,046**	**$ 51.30**

The intrinsic value of restricted stock released was $7.7 million, $3.7 million, and $2.7 million for the years ended December 31, 2016, 2015, and 2014, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was $3.1 million, $1.3 million, and $1.0 million, respectively.

As of December 31, 2016, approximately $5.1 million of unrecognized compensation cost related to restricted stock was expected to be recognized over the next 1.9 years on a weighted-average basis.

During the first quarter of 2017, the Compensation Committee awarded 82,622 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 $58.10 per share.

Performance Units

In 2016, 2015, and 2014, the Compensation Committee awarded 297,305; 195,365; and 233,735 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $19.1 million, $13.2 million, and $14.8 million were settled during 2016, 2015, and 2014, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units for the same years was approximately $6.8 million, $4.8 million, and $5.3 million, respectively.

As of December 31, 2016, approximately $10.2 million of unrecognized compensation cost related to performance units was expected to be recognized over the next 1.4 years on a weighted-average basis.

During the first quarter of 2017, we settled performance units with an intrinsic value of $6.1 million. The actual tax benefit realized from the distribution of these awards was $1.8 million. In January 2017, the Compensation Committee also awarded 237,650 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 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 13, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2016, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of investees accounted for by the equity method totaled approximately $6.3 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2016.

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

Share Repurchase Program

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 2016, 2015, or 2014, other than for the Integrys acquisition. See Note 2, Acquisitions, for more information.

In December 2013, our Board of Directors authorized a share repurchase program for the purchase of up to $300.0 million of our common stock through open market purchases or privately negotiated transactions from January 1, 2014, through the end of 2017. On June 22, 2014, in connection with entering into the Merger Agreement, the Board of Directors terminated this share repurchase program. The following table identifies shares purchased during the year ended December 31:

	2016		2015		2014	
(in millions)	Shares	Cost	Shares	Cost	Shares	Cost
Under share repurchase programs	—	$ —	—	$ —	0.4	$ 18.6
To fulfill exercised stock options and restricted stock awards	**1.8**	**108.0**	1.5	74.7	2.3	104.6
Total	**1.8**	**$ 108.0**	1.5	$ 74.7	$ 2.7	$ 123.2

Common Stock Dividends

During the year ended December 31, 2016, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 21, 2016	March 1, 2016	$0.4950	First quarter
April 21, 2016	June 1, 2016	$0.4950	Second quarter
July 21, 2016	September 1, 2016	$0.4950	Third quarter
October 20, 2016	December 1, 2016	$0.4950	Fourth quarter

On January 19, 2017, our Board of Directors increased our quarterly dividend to $0.52 per share effective with the first quarter of 2017 dividend payment, which equates to an annual dividend of $2.08 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.

NOTE 12—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2016 and 2015:

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

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)	2016	2015
Commercial paper		
Amount outstanding at December 31	**$ 860.2**	$ 1,095.0
Average interest rate on amounts outstanding at December 31	**0.96%**	0.68%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2016, was $882.3 million with a weighted-average interest rate during the period of 0.66%.

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, 2016, all companies were in compliance with their respective ratio.

As of December 31, 2016, we had $1,620.7 million of available capacity under our bank back-up credit facilities and $860.2 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:

(in millions)	Maturity	2016
WEC Energy Group	December 2020	**$ 1,050.0**
WE	December 2020	**500.0**
WPS	December 2020	**250.0**
WG	December 2020	**350.0**
PGL	December 2020	**350.0**
Total short-term credit capacity		**$ 2,500.0**
Less:		
Letters of credit issued inside credit facilities		**$ 19.1**
Commercial paper outstanding		**860.2**
Available capacity under existing agreements		**$ 1,620.7**

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 14—LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

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

Wisconsin Gas LLC

In September 2016, WG issued $200.0 million of 3.71% Debentures due September 30, 2046. The net proceeds were used to repay short-term debt.

The Peoples Gas Light and Coke Company

In December 2016, PGL issued $150.0 million of 3.65% Series DDD Bonds due December 15, 2046. The net proceeds were used for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

In November 2016, PGL issued $50.0 million of 3.65% Series CCC Bonds due December 15, 2046. The net proceeds were used to repay at maturity PGL's $50.0 million aggregate principal amount outstanding of 2.21% First and Refunding Mortgage Bonds, Series XX.

In June 2016, PGL issued commercial paper to redeem at par, its $50.0 million of 4.30% Series RR First and Refunding Mortgage Bonds that were due in 2035.

W.E. Power, LLC

During 2017, $5.6 million of We Power's outstanding $106.7 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, 2016.

During 2017, $4.6 million of We Power's outstanding $126.1 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, 2016.

During 2017, $10.8 million of We Power's outstanding $204.8 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, 2016.

During 2017, $8.5 million of We Power's outstanding $170.9 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, 2016.

Integrys Holding, Inc.

In June 2016, Integrys's $50.0 million of 8.00% unsecured senior notes matured and were repaid with contributions from WEC Energy Group, which were funded by commercial paper issued by WEC Energy Group.

In February 2016, Integrys repurchased and retired $154.9 million aggregate principal amount of its 6.11% Junior Notes for a purchase price of $128.6 million, plus accrued and unpaid interest, through a modified “dutch auction” tender offer. The gain associated with this repurchase was included in other income, net on our income statement. In connection with this transaction, Integrys issued approximately $66.4 million of additional common stock to WEC Energy Group in satisfaction of its obligations under a replacement capital covenant relating to the 6.11% Junior Notes. Effective December 1, 2016, the remaining $114.9 million aggregate principal amount of the 6.11% Junior Notes bears interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.12% and will reset quarterly.

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, 2016:

(in millions)	Payments
2017	$ 154.5
2018	836.1
2019	357.7
2020	684.4
2021	336.2
Thereafter	6,953.5
Total	$ 9,322.4

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

As of December 31, 2016, 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, 2016, 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 6.25% Series A Junior Subordinated Notes (6.25% 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 6.25% 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.

Effective May 2017, the $500 million of 6.25% Junior Notes will bear interest at the three-month LIBOR plus 211.25 basis points and will reset quarterly.

In connection with Integrys's outstanding 6.11% 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 6.11% 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 $37.6 million and $36.2 million in lease payments during 2016 and 2015, 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 $29.6 million as of December 31, 2016, 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:

(in millions)	**2016**	**2015**
Long-term power purchase commitment	**$ 140.3**	$ 140.3
Accumulated amortization	**(109.5)**	(103.9)
Total leased facilities	**$ 30.8**	$ 36.4

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2016 are as follows:

(in millions)	Payments
2017	$ 13.9
2018	14.7
2019	15.5
2020	16.4
2021	17.2
Thereafter	7.6
Total minimum lease payments	85.3
Less: Estimated executory costs	(39.9)
Net minimum lease payments	45.4
Less: Interest	(15.8)
Present value of net minimum lease payments	29.6
Less: Due currently	(2.7)
Long-term obligations under capital lease	**$ 26.9**

NOTE 15—INCOME TAXES

Income Tax Expense

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

(in millions)	2016	2015	2014
Current tax expense	**$ 72.7**	$ 15.1	$ 33.6
Deferred income taxes, net	**498.7**	420.4	329.2
Investment tax credit, net	**(4.9)**	(1.7)	(1.1)
Total income tax expense	**$ 566.5**	$ 433.8	$ 361.7

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:

	2016		2015		2014	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 526.4**	**35.0 %**	$ 375.5	35.0 %	$ 332.5	35.0 %
State income taxes net of federal tax benefit	**72.8**	**4.8 %**	73.1	6.8 %	50.5	5.3 %
Production tax credits	**(15.7)**	**(1.1)%**	(17.4)	(1.6)%	(17.4)	(1.8)%
AFUDC – Equity	**(8.8)**	**(0.6)%**	(7.1)	(0.7)%	(1.9)	(0.2)%
Investment tax credit restored	**(4.9)**	**(0.3)%**	(1.7)	(0.2)%	(1.1)	(0.2)%
Other, net	**(3.3)**	**(0.2)%**	11.4	1.1 %	(0.9)	(0.1)%
Total income tax expense	**$ 566.5**	**37.6 %**	$ 433.8	40.4 %	$ 361.7	38.0 %

Deferred Income Tax Assets and Liabilities

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

(in millions)	2016	2015
Deferred tax assets		
Future tax benefits	**$ 430.4**	$ 382.8
Employee benefits and compensation	**222.0**	229.9
Deferred revenues	**207.2**	219.9
Property-related	**54.5**	59.5
Other	**230.6**	177.1
Total deferred tax assets	**1,144.7**	1,069.2
Valuation allowance	**(15.0)**	(17.1)
Net deferred tax assets	**$ 1,129.7**	$ 1,052.1
Deferred tax liabilities		
Property-related	**$ 4,979.3**	$ 4,451.5
Investment in transmission affiliate	**476.9**	420.4
Employee benefits and compensation	**401.6**	428.9
Deferred transmission costs	**93.1**	76.7
Other	**325.4**	296.9
Total deferred tax liabilities	**6,276.3**	5,674.4
Deferred tax liability, net	**$ 5,146.6**	$ 4,622.3

Consistent with rate-making treatment, deferred taxes 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, 2016 and 2015 are summarized in the tables below:

2016 *(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**
Balance as of December 31, 2016	**$ 899.6**	**$ 430.4**	**$ (15.0)**	

2015 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2015				
Federal net operating loss	$ 412.3	$ 144.3	**$** —	2031
Federal foreign tax credit	—	15.2	(15.2)	2017
Other federal tax credit	—	207.8	—	2025
Charitable contribution	4.7	1.9	(1.9)	2016
State net operating loss	185.9	9.3	—	2024
State tax credit	—	4.3	—	2016
Balance as of December 31, 2015	$ 602.9	$ 382.8	$ (17.1)	

Valuation allowances of $15.0 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 the extension 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)	2016	2015
Balance as of January 1	**$ 9.5**	$ 7.2
Acquired legacy Integrys unrecognized tax benefits	**—**	3.6
Additions for tax positions of prior years	**6.7**	0.3
Additions based on tax positions related to the current year	**1.1**	0.2
Reductions for tax positions of prior years	**(1.0)**	(1.1)
Reductions due to statute of limitations	**(1.8)**	—
Settlements during the period	**—**	(0.7)
Balance as of December 31	**$ 14.5**	$ 9.5

The amount of unrecognized tax benefits as of December 31, 2016 and 2015, excludes deferred tax assets related to uncertainty in income taxes of $6.6 million and $6.2 million, respectively. As of December 31, 2016 and 2015, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $7.9 million and $2.2 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, 2016, 2015, and 2014, we recognized $0.2 million, zero, and $0.3 million of accrued interest in our income statements, respectively. For the years ended December 31, 2016, 2015, and 2014, we recognized no penalties in our income statements. For the year ended December 31, 2016, we had $0.8 million of interest accrued and no penalties accrued on our balance sheets. For the year ended December 31, 2015, we had $0.7 million of interest accrued and $0.1 million of 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, 2016, we were subject to examination by state or local tax authorities for the 2011 through 2016 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Years
Federal	2013–2016
Illinois	2013–2016
Michigan	2012–2016
Minnesota	2014–2016
Wisconsin	2011–2016

NOTE 16—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at December 31, 2016	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees				
Standby letters of credit (1)	**$ 29.4**	$ 27.9	$ 1.5	$ —
Surety bonds (2)	**10.9**	10.3	0.6	—
Other guarantees (3)	**7.6**	0.5	—	7.1
Total guarantees	**$ 47.9**	$ 38.7	$ 2.1	$ 7.1

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

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

(3) Consists of $7.6 million related to other indemnifications, for which a liability of $7.1 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 nonqualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

Generally, former Wisconsin Energy Corporation employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. New Wisconsin Energy Corporation management employees hired after December 31, 2014 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:

	Pension Costs		OPEB Costs	
(in millions)	**2016**	**2015**	**2016**	**2015**
Change in benefit obligation				
Obligation at January 1	**$ 3,083.0**	$ 1,505.5	**$ 842.0**	$ 397.7
Obligation assumed from acquisition	**—**	1,594.0	**—**	493.0
Service cost	**45.4**	30.4	**26.1**	20.7
Interest cost	**130.8**	94.3	**37.0**	26.7
Participant contributions	**—**	—	**16.4**	12.7
Plan amendments	**(3.0)**	—	**(18.9)**	—
Actuarial loss (gain)	**71.7**	14.6	**(36.5)**	(74.0)
Benefit payments	**(269.1)**	(156.0)	**(49.1)**	(36.2)
Federal subsidy on benefits paid	**N/A**	N/A	**1.4**	1.6
Plan curtailment	**—**	0.2	**—**	(0.2)
Obligation at December 31	**$ 3,058.8**	$ 3,083.0	**$ 818.4**	$ 842.0
Change in fair value of plan assets				
Fair value at January 1	**$ 2,755.1**	$ 1,444.6	**$ 749.8**	$ 333.5
Assets received from acquisition	**—**	1,420.9	**—**	442.1
Actual return on plan assets	**199.4**	(62.1)	**51.5**	(15.6)
Employer contributions	**23.8**	107.7	**4.9**	13.3
Participant contributions	**—**	—	**16.4**	12.7
Benefit payments	**(269.1)**	(156.0)	**(49.1)**	(36.2)
Fair value at December 31	**$ 2,709.2**	$ 2,755.1	**$ 773.5**	$ 749.8
Funded status at December 31	**$ (349.6)**	$ (327.9)	**$ (44.9)**	$ (92.2)

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

	Pension Costs		OPEB Costs	
(in millions)	2016	2015	2016	2015
Other long-term assets	**$ 74.4**	$ 74.1	**$ 29.7**	$ 50.1
Pension and OPEB obligations *	**424.0**	402.0	**74.6**	142.3
Total net liabilities	**$ (349.6)**	$ (327.9)	**$ (44.9)**	$ (92.2)

* Includes $0.8 million of pension and $0.4 million of OPEB obligations classified as liabilities held for sale as of December 31, 2015. These amounts are included in other current liabilities on our balance sheets.

The accumulated benefit obligation for all defined benefit pension plans was $2,939.9 million and $2,936.4 million as of December 31, 2016, and 2015, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2016	2015
Projected benefit obligation	**$ 1,667.0**	$ 1,706.6
Accumulated benefit obligation	**1,549.5**	1,560.5
Fair value of plan assets	**1,242.9**	1,304.6

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

	Pension Costs		OPEB Costs	
(in millions)	2016	2015	2016	2015
Accumulated other comprehensive loss (pre-tax) (1)				
Net actuarial loss (gain)	**$ 12.0**	$ 11.4	**$ (1.0)**	$ (0.6)
Total	**$ 12.0**	$ 11.4	**$ (1.0)**	$ (0.6)
Net regulatory assets (2)				
Net actuarial loss	**$ 1,240.7**	$ 798.1	**$ 25.8**	$ 23.7
Prior service costs (credits)	**10.5**	4.7	**(87.9)**	(3.3)
Total	**$ 1,251.2**	$ 802.8	**$ (62.1)**	$ 20.4

(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 2017:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$ 87.2	$ 5.8
Prior service costs (credits)	3.0	(11.2)
Total 2017 – estimated amortization	$ 90.2	$ (5.4)

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

	Pension Costs			OPEB Costs		
(in millions)	2016	2015	2014	2016	2015	2014
Service cost	**$ 45.4**	$ 30.4	$ 10.1	**$ 26.1**	$ 20.7	$ 8.5
Interest cost	**130.8**	94.3	68.1	**37.0**	26.7	17.8
Expected return on plan assets	**(195.9)**	(155.6)	(98.6)	**(52.7)**	(39.6)	(23.7)
Plan settlement	**16.5**	—	—	**—**	—	—
Plan curtailment	**—**	(0.3)	—	**—**	—	—
Amortization of prior service cost (credit)	**3.4**	2.2	2.1	**(9.4)**	(6.4)	(1.8)
Amortization of net actuarial loss	**82.9**	68.5	36.7	**8.5**	3.9	1.2
Net periodic benefit cost	**$ 83.1**	$ 39.5	$ 18.4	**$ 9.5**	$ 5.3	$ 2.0

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

	Pension		OPEB	
	2016	**2015**	**2016**	**2015**
Discount rate	**4.16%**	4.46%	**4.14%**	4.38%
Rate of compensation increase	**3.60%**	4.00%	**N/A**	N/A
Assumed medical cost trend rate	**N/A**	N/A	**7.00%**	7.50%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2021**	2021

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		
	2016	**2015**	**2014**
Discount rate	**4.35%**	4.11%	5.00%
Expected return on plan assets	**7.12%**	7.37%	7.25%
Rate of compensation increase	**3.75%**	4.00%	4.00%

	OPEB Costs		
	2016	**2015**	**2014**
Discount rate	**4.38%**	4.09%	4.95%
Expected return on plan assets	**7.25%**	7.54%	7.50%
Assumed medical cost trend rate (Pre 65/Post 65)	**7.50%**	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 2017, the expected return on assets assumption is 7.11% 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, 2016, 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	$ 8.5	$ (6.9)
Effect on health care component of the accumulated postretirement benefit obligations	49.6	(39.5)

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 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 Integrys pension trust target asset allocation is 60% equity investments and 40% fixed income investments. The Wisconsin Energy Corporation OPEB trusts' target asset allocations are 60% equity investments and 40% fixed income investments. The two largest OPEB trusts for Integrys have target asset allocations of 50% equity investments and 50% fixed income, and 45% equity investments and 55% 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(s), 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. Following our adoption of ASU 2015-07 on January 1, 2016, the assets that are not subject to leveling are investments that are valued using the net asset value per share (or its equivalent) practical expedient. We have applied this approach retrospectively to the 2015 table for comparability.

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

	December 31, 2016							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
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
Total	$ 331.7	$ 995.9	$ 15.4	$ 2,709.2	$ 66.6	$ 150.3	$ 1.3	$ 773.5

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

	December 31, 2015							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ 17.0	$ 29.6	$ —	$ 46.6	$ 10.5	$ 1.0	$ —	$ 11.5
Equity securities:								
United States Equity	132.6	3.4	—	136.0	24.6	0.1	—	24.7
International Equity	103.9	—	—	103.9	21.4	—	—	21.4
Fixed income securities: *								
United States Bonds	11.4	797.3	—	808.7	0.3	122.0	—	122.3
International Bonds	—	80.3	—	80.3	—	8.1	—	8.1
Private Equity and Real Estate	—	—	5.5	5.5	—	—	0.4	0.4
	$ 264.9	$ 910.6	$ 5.5	$ 1,181.0	$ 56.8	$ 131.2	$ 0.4	$ 188.4
Investments measured at net asset value				$ 1,574.1				$ 561.4
Total	$ 264.9	$ 910.6	$ 5.5	$ 2,755.1	$ 56.8	$ 131.2	$ 0.4	$ 749.8

* 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:

	Private Equity and Real Estate		United States Bonds
(in millions)	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
Ending balance at December 31, 2016	$ 14.6	$ 1.3	$ 0.8

	Private Equity and Real Estate	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2015	$ —	$ —
Purchases	5.5	0.4
Ending balance at December 31, 2015	$ 5.5	$ 0.4

Cash Flows

In January 2017, we contributed $100.0 million to the pension plans. We expect to contribute an additional $13.2 million to the pension plans and $0.1 million to the OPEB plans in 2017, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

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

(in millions)	Pension Costs	OPEB Costs
2017	$ 215.7	$ 41.8
2018	217.1	49.6
2019	226.5	49.0
2020	233.1	50.9
2021	230.0	53.1
2022-2026	1,031.5	278.5

Savings Plans

We sponsor 401(k) savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. 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 $44.3 million in 2016, $48.0 million in 2015, and $14.2 million in 2014.

NOTE 18—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

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2016, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2017	2018	2019	2020	2021	Later Years
Electric utility:								
Nuclear	2033	$ 9,599.8	$ 415.3	$ 420.1	$ 445.4	$ 475.1	$ 501.1	$ 7,342.8
Purchased power	2027	693.3	111.3	75.9	66.2	66.3	63.9	309.7
Coal supply and transportation	2019	455.0	269.4	140.3	45.3	—	—	—
Natural gas utility supply and transportation	2028	1,229.4	341.7	285.5	237.5	159.7	78.6	126.4
Total		$ 11,977.5	$ 1,137.7	$ 921.8	$ 794.4	$ 701.1	$ 643.6	$ 7,778.9

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 $15.1 million, $12.7 million, and $4.8 million in 2016, 2015, and 2014, respectively.

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

Year Ending December 31	Payments *(in millions)*
2017	$ 9.9
2018	8.8
2019	5.9
2020	5.3
2021	5.5
Later years	60.1
Total	$ 95.5

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as SO_2, NOx, fine particulates, mercury, and GHGs; water 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 and super-critical pulverized coal 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

Cross-State Air Pollution Rule – In July 2011, the EPA issued the CSAPR, which replaced a previous rule, the Clean Air Interstate Rule. The purpose of the CSAPR was to limit the interstate transport of NOx and SO_2 that contribute to fine particulate matter and ozone nonattainment in downwind states through a proposed allowance allocation and trading plan. After several lawsuits and related appeals, in October 2014, the D.C. Circuit Court of Appeals issued a decision that allowed the EPA to begin implementing CSAPR on January 1, 2015. The emissions budgets of Phase I of the rule applied in 2015 and 2016, while the Phase II emissions budgets discussed below apply to 2017 and beyond.

In December 2015, the EPA published its proposed update to the CSAPR for the 2008 ozone NAAQS and issued the final rule in September 2016. Starting in 2017, this rule requires reductions in the ozone season (May 1 through September 30) NOx emissions from power plants in 23 states in the eastern United States, including Wisconsin. The EPA updated Phase II CSAPR NOx ozone season budgets for electric generating units in the affected states. In the final rule, the EPA significantly increased the NOx ozone season budget from the proposed rule for Wisconsin starting in 2017. We believe we are well positioned to meet the rule requirements and do not expect to incur significant costs to comply with this rule.

Sulfur Dioxide National Ambient Air Quality Standards – The EPA issued a revised 1-Hour SO_2 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 March 2015, a federal court entered a consent decree between the EPA and the Sierra Club and others agreeing to specific actions related to implementing the revised standard for areas containing large sources emitting above a certain threshold level of SO_2. The consent decree required the EPA to complete attainment designations for certain areas with large sources by no later than July 2016. SO_2 emissions from PIPP are above the consent decree emission threshold, which means that the Marquette area required action earlier than would otherwise have been required under the revised NAAQS. However, we were able to show through modeling that the area should be designated as attainment. In July 2016, the EPA finalized its recommendation and published a notice in the Federal Register designating Marquette County, Michigan as unclassified/attainment, effective September 2016.

In June 2016, we provided modeling to the WDNR that shows the area around the Weston Power Plant to be in compliance. Based upon the submittal, the WDNR provided final modeling to the EPA demonstrating the area around the Weston Power Plant to be in compliance. We expect that the EPA will consider the WDNR's recommendation and finalize its recommended designation in August 2017, for finalization by the end of 2017.

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.

8-Hour Ozone National Ambient Air Quality Standards – The EPA completed its review of the 2008 8-hour ozone standard in November 2014, and announced a proposal to tighten (lower) the NAAQS. In October 2015, the EPA released the final rule, which lowered the limit for ground-level ozone. This is expected to cause nonattainment designations for some counties in Wisconsin with potential future impacts for our fossil-fueled power plant fleet. 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 and are in the process of reviewing and determining potential impacts resulting from this rule. We believe we are well positioned to meet the rule requirements and do not expect to incur significant costs to comply with this rule.

Mercury and Other Hazardous Air Pollutants – In December 2011, the EPA issued the final MATS rule, which imposed stringent limitations on emissions of mercury and other hazardous air pollutants from coal and oil-fired electric generating units beginning in April 2015. In addition, both Wisconsin and Michigan have state mercury rules that require a 90% reduction of mercury; however, these rules are not in effect as long as MATS is in place. In June 2015, the Supreme Court ruled on a challenge to the MATS rule and remanded the case back to the D.C. Circuit Court of Appeals, ruling that the EPA failed to appropriately consider the cost of the regulation. The MATS rule remains in effect until the D.C. Circuit Court of Appeals takes action on the EPA's April 2016 updated cost evaluation.

We believe that the WE and WPS fleets are well positioned to comply with the final MATS rule and do not expect to incur any significant additional costs to comply with this regulation. The addition of a dry sorbent injection system for further control of mercury and acid gases at PIPP was placed into service in March 2016, allowing PIPP to be in compliance with MATS. Construction and testing of the ReACT™ multi-pollutant control system at Weston Unit 3 is complete, and the unit is currently in compliance with both MATS and the WPS Consent Decree emission requirements.

Climate Change – In 2015, the EPA issued the Clean Power Plan, a final rule regulating GHG emissions from existing generating units, 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 final rule for existing fossil-fueled generating units, numerous states (including Wisconsin and Michigan), trade associations, and private 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 Clean Power Plan 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. In addition, in February 2016, the Governor of Wisconsin issued Executive Order 186, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan. The D.C. Circuit Court of Appeals heard the case in September 2016.

The final rule for existing fossil-fueled generating units 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. The building blocks used by the EPA to determine each state's emission reduction requirements include a combination of improving power plant efficiency, increasing reliance on combined cycle natural gas units, and adding new renewable energy resources. We continue to evaluate possible reduction opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions, given the uncertain future of the Clean Power Plan and current fuel and technology markets. Our evaluation to date indicates that the Clean Power Plan, as well as current fuel markets and advances in technology, are not expected to result in significant additional compliance costs, including capital expenditures, but could impact how we operate our existing fossil-fueled power plants and biomass facility.

However, the timelines for the 2022 through 2029 interim goals and the 2030 final goal for states, as well as all other aspects of the rule, likely will be changed due to the stay and subsequent legal proceedings. With the new Federal Executive Administration as of January 2017, the Clean Power Plan, or its successor, could be significantly changed from the final rule of October 2015. Notwithstanding the potential changes to the Clean Power Plan, addressing climate change is an integral component of our strategic planning process. We continue to reshape our portfolio of electric generation facilities with investments that will improve our environmental performance, including reduced GHG intensity of our operating fleet. As the regulation of GHG emissions takes shape, our plan is to work with our industry partners, environmental groups, and the State of Wisconsin, with a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. We continue to evaluate numerous options in order to meet our CO_2 reduction goal, such as increased utilization 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.

Draft Federal Plan and Model Trading Rules (Model Rules) were also published in October 2015 for use in developing state plans or for use in states where a plan is not submitted or approved. In December 2015, the state of Wisconsin submitted petitions for reconsideration of the EPA's final standards for existing, as well as for new, modified, and reconstructed generating units. A petition for reconsideration of the EPA's final standards for existing generating units was also submitted jointly by the Wisconsin utilities. Among other things, the petitions narrowly asked the EPA to consider revising the state goal for existing units to reflect the 2013 retirement of the Kewaunee Power Station, which could lower the state's CO_2 equivalent reduction goal by about 10%. In May 2016, the EPA denied the state of Wisconsin's petition for reconsideration related to new, modified, and reconstructed generating units, except that the EPA deferred the portion related to the treatment of biomass. The EPA has not issued decisions yet regarding the above referenced petitions for reconsideration of the final EPA standards for existing generating units. In December 2016, the EPA withdrew the draft Model Rules and accompanying draft documents from the review process and made working drafts available to the public. They are not final documents, are not signed by the Administrator, and will not be published in the Federal Register. The EPA’s docket will remain open, with the potential for completing the agency’s work on these materials and finalizing them at a later date.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2015, we reported aggregated CO_2 equivalent emissions of approximately 31.0 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 29.6 million metric tonnes to the EPA for 2016. The level of CO_2 and other GHG emissions vary from year to year and are dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent amounts related to the natural gas that our natural gas utilities distribute and sell. For 2015, we reported aggregated CO_2 equivalent emissions of approximately 27.2 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 26.7 million metric tonnes to the EPA for 2016.

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 evaluate the available IM options for Pulliam Units 7 and 8. We also expect that limited studies will be required to support the future WDNR 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. BTA determinations for EM will be made in future permit reissuances for Pulliam Units 7 and 8, Weston Units 2 through 4, PWGS, Pleasant Prairie Power Plant, PIPP, and OC 5 through OC 8.

During 2017 and 2018, we will continue to complete studies and evaluate options to address the EM BTA requirements at our plants. With the exception of Pleasant Prairie Power Plant and Weston Units 3 and 4 (which all have existing cooling towers that meet EM BTA requirements) and VAPP, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at our facilities. We also expect that limited studies to support WDNR BTA determinations will be conducted at the Weston facility. 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 EM BTA requirements based on low capacity use of the unit. Based on discussions with the MDEQ, if we provide information about unit retirements with our next National Pollutant Discharge Elimination System permit application and then submit a signed certification by August 2017 stating that PIPP will be retired no later than the end of the next permit cycle (assumed to be October 1, 2022), then the EM BTA requirements will be waived. Entrainment studies are currently being conducted at Pulliam Units 7 and 8 and were recently completed at PIPP. See UMERC discussion in Note 22, Regulatory Environment, regarding the potential retirement of PIPP.

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 Guidelines – The EPA's final steam electric effluent guidelines rule took effect in January 2016 and applies to discharges of wastewater from our power plant processes in Wisconsin and Michigan. This rule is being litigated in the United States Court of Appeals for the Fifth Circuit and may result in changes to the discharge requirements. The WDNR and MDEQ will continue to modify the state rules as necessary and incorporate the new requirements into our facility permits, which are renewed every five years. We expect the new requirements to be phased in between 2018 and 2023 as our permits are renewed. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, these standards will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use. The final rule phases 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 will require additional zero liquid discharge or other advanced treatment capital improvements for the Oak Creek site and Pleasant Prairie facilities. The rule also requires 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 will be required at OC 7, OC 8, the Pleasant Prairie units, Pulliam Units 7 and 8, and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate a total cost range of $80 million to $110 million for these advanced treatment and bottom ash transport systems. A similar system would be required at PIPP if we were not expecting to retire the plant. See UMERC discussion in Note 22, Regulatory Environment, regarding the potential retirement of PIPP.

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:

(in millions)	**2016**	**2015**
Regulatory assets	**$ 702.7**	$ 697.0
Reserves for future remediation	**633.4**	628.0

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 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 2016 through 2018, increases the requirement to 12.5% for years 2019 through 2020, and increases the requirement to 15.0% for 2021. WE and WPS were in compliance with these requirements as of December 31, 2016. 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.

Paris Generating Station Units 1 and 4 Construction Permit

In December 2013, Act 91 was signed into law in Wisconsin, creating a process by which the EPA and WDNR were able to revise the regulations and emissions rates applicable to Paris Generating Station Units 1 and 4. Act 91, along with a new construction permit, allowed those units to restart after a temporary outage. In October 2014, the Sierra Club filed for a contested case hearing with the WDNR challenging this permit. In February 2013, the Sierra Club also filed for a contested case hearing with the WDNR in connection with the administrative order issued in this matter, which was granted. The Sierra Club has withdrawn the contested case hearing request, thereby concluding this matter.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam – 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 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 (including refueling, repowering, and/or retirement of units),
- 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 March 2016, WPS submitted a proposed revision to the EPA 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. These proposed revisions were approved by the EPA in May 2016. The revisions to the environmental projects are not expected to materially impact the overall costs noted above.

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.

Also, in May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of December 31, 2016. It is unknown whether the Sierra Club will take further action in the future.

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 (including refueling, repowering, and/or retirement of units),
- 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. In the first quarter of 2015, management of the joint owners recommended that Edgewater Unit 4 be retired in December 2018. However, a final decision on how to address the requirement for this unit has not yet been made by the joint owners, as early retirement is contingent on various operational and market factors, and other alternatives to retirement are still available.

NOTE 19—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	December 31, 2016			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets				
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
Total derivative assets	$ 10.3	$ 26.2	$ 5.1	$ 41.6
Investments held in rabbi trust	$ 103.9	$ —	$ —	$ 103.9
Derivative liabilities				
Natural gas contracts	$ 0.2	$ 0.2	$ —	$ 0.4
Petroleum products contracts	0.1	—	—	0.1
Coal contracts	—	1.9	—	1.9
Total derivative liabilities	$ 0.3	$ 2.1	$ —	$ 2.4

	December 31, 2015			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 1.6	$ 1.5	$ —	$ 3.1
Petroleum products contracts	1.2	—	—	1.2
FTRs	—	—	3.6	3.6
Coal contracts	—	2.0	—	2.0
Total derivative assets	$ 2.8	$ 3.5	$ 3.6	$ 9.9
Investments held in rabbi trust	$ 39.8	$ —	$ —	$ 39.8
Derivative liabilities				
Natural gas contracts	$ 16.5	$ 25.3	$ —	$ 41.8
Petroleum products contracts	4.9	—	—	4.9
Coal contracts	—	12.3	—	12.3
Total derivative liabilities	$ 21.4	$ 37.6	$ —	$ 59.0

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 20, 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:

(in millions)	2016	2015	2014
Balance at the beginning of the period	**$ 3.6**	$ 7.0	$ 3.5
Realized and unrealized (losses) gains	**(0.2)**	1.3	—
Purchases	**15.2**	3.9	15.6
Sales	**(0.2)**	(0.1)	—
Settlements	**(13.3)**	(11.9)	(12.1)
Acquisition of Integrys	**—**	(1.3)	—
Transfers out of level 3	**—**	4.7	—
Balance at the end of the period	**$ 5.1**	$ 3.6	$ 7.0

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:

	2016		2015	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock	**$ 30.4**	**$ 28.8**	$ 30.4	$ 27.3
Long-term debt, including current portion *	**$ 9,285.8**	**$ 9,818.2**	$ 9,221.9	$ 9,681.0

* The carrying amount of long-term debt excludes capital lease obligations of $29.6 million and $59.9 million at December 31, 2016 and December 31, 2015, respectively.

NOTE 20—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

(in millions)	December 31, 2016 Derivative Assets	December 31, 2016 Derivative Liabilities	December 31, 2015 Derivative Assets	December 31, 2015 Derivative Liabilities
Other current				
Natural gas contracts	**$ 31.4**	**$ 0.4**	$ 2.6	$ 38.5
Petroleum products contracts	**0.2**	**0.1**	0.9	3.8
FTRs	**5.1**	**—**	3.6	—
Coal contracts	**1.5**	**1.4**	1.7	6.7
Total other current	**$ 38.2**	**$ 1.9**	$ 8.8	$ 49.0
Other long-term				
Natural gas contracts	**$ 2.9**	**$ —**	$ 0.5	$ 3.3
Petroleum products contracts	**—**	**—**	0.3	1.1
Coal contracts	**0.5**	**0.5**	0.3	5.6
Total other long-term	**$ 3.4**	**$ 0.5**	$ 1.1	$ 10.0
Total	**$ 41.6**	**$ 2.4**	$ 9.9	$ 59.0

Our estimated notional sales volumes and realized gains (losses) were as follows:

(in millions)	December 31, 2016 Volume	December 31, 2016 Gains (Losses)	December 31, 2015 Volume	December 31, 2015 Gains (Losses)	December 31, 2014 Volume	December 31, 2014 Gains
Natural gas contracts	151.1 Dth	**$ (59.6)**	86.2 Dth	$ (50.5)	40.5 Dth	$ 7.3
Petroleum products contracts	14.7 gallons	**(3.2)**	7.8 gallons	(1.9)	9.2 gallons	0.5
FTRs	33.7 MWh	**13.3**	27.3 MWh	6.7	26.1 MWh	12.7
Total		**$ (49.5)**		$ (45.7)		$ 20.5

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

(in millions)	December 31, 2016 Derivative Assets	December 31, 2016 Derivative Liabilities	December 31, 2015 Derivative Assets	December 31, 2015 Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 41.6**	**$ 2.4**	$ 9.9	$ 59.0
Gross amount not offset on the balance sheet *	**(4.9)**	**(0.5)**	(3.0)	(22.5)
Net amount	**$ 36.7**	**$ 1.9**	$ 6.9	$ 36.5

* Includes cash collateral received of $4.4 million at December 31, 2016, and cash collateral posted of $19.5 million at December 31, 2015.

At December 31, 2016 and 2015, we had posted cash collateral of $16.4 million and $42.3 million, respectively, in our margin accounts. At December 31, 2016, we had also received cash collateral of $4.4 million in our margin accounts. We had not received any cash collateral at December 31, 2015. 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, 2016 and 2015 was $0.2 million and $23.8 million, respectively. At December 31, 2016 and 2015, 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, 2016, we would not have been required to post any collateral. At December 31, 2015, we would have been required to post collateral of $18.0 million.

During 2015, we settled several forward interest rate swap agreements entered into to mitigate interest 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 hedging accounting treatment, the proceeds of $19.0 million received upon settlement of these agreements 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.

During 2016, we reclassified $2.2 million 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 21—VARIABLE INTEREST ENTITIES

In February 2015, the FASB issued ASU 2015-02, Amendments to the Consolidation Analysis. This ASU focuses on the consolidation analysis for companies that are required to evaluate whether they should consolidate certain legal entities. It emphasizes the risk of loss when determining a controlling financial interest and amends the guidance for assessing how related party relationships affect the consolidation analysis of variable interest entities. We adopted the standard upon its effective date in the first quarter of 2016, and our adoption resulted in no changes to our disclosures or financial statement presentation.

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.

American Transmission Company

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. See Note 4, Investment in American Transmission Company, for more information.

The significant assets and liabilities related to ATC recorded on our balance sheets included our equity investment and accounts payable. At December 31, 2016, and 2015, our equity investment was $1,443.9 million and $1,380.9 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC. In addition, we had $28.7 million and $28.3 million of accounts payable due to ATC at December 31, 2016, and 2015, respectively, for network transmission services.

Purchased Power Agreement

We have identified 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 five 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 $85.3 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, 2016, 2015, and 2014, were $54.2 million, $53.6 million, and $53.0 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

NOTE 22—REGULATORY ENVIRONMENT

Wisconsin Electric Power Company

2015 Wisconsin 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.

- 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 approved a change in rate design for WE, which included higher fixed charges to better match the related fixed costs of providing service. 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 will be recovered from customers with interest, in a future rate case.

In January 2015, certain parties appealed a portion of the PSCW's final decision adopting WE's specific rate design changes, including new charges for customer-owned generation within its service territory. The Dane County Circuit Court, in its November 2015 order, ruled that there was not enough evidence provided in WE's rate case to support a demand charge for customer-owned generation. As a result, this demand charge did not take effect on January 1, 2016. No other rates approved by the PSCW in the rate case were impacted by the Dane County Circuit Court order.

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.

2013 Wisconsin Rate Order

In March 2012, WE initiated a rate proceeding with the PSCW. In December 2012, the PSCW approved the following rate adjustments, effective January 1, 2013:

- A net bill increase related to non-fuel costs for WE's retail electric customers of approximately $70.0 million (2.6%) in 2013. This amount reflected an offset of approximately $63.0 million (2.3%) for bill credits related to the proceeds of the Treasury Grant, including associated tax benefits. Absent this offset, the retail electric rate increase for non-fuel costs was approximately $133.0 million (4.8%) in 2013.

- An electric rate increase for WE's electric customers of approximately $28.0 million (1.0%) in 2014, and a $45.0 million (-1.6%) reduction in bill credits.

- Recovery of a forecasted increase in fuel costs of approximately $44.0 million (1.6%) in 2013.

- A rate decrease of approximately $8.0 million (-1.9%) for WE's natural gas customers in 2013, with no rate adjustment in 2014. The WE rates reflected a $6.4 million reduction in bad debt expense.

- An increase of approximately $1.3 million (6.0%) for WE's Downtown Milwaukee (Valley) steam utility customers in 2013 and another $1.3 million (6.0%) in 2014.

- An increase of approximately $1.0 million (7.0%) in 2013 and $1.0 million (6.0%) in 2014 for WE's Milwaukee County steam utility customers.

Based on the PSCW order, the authorized ROE for WE remained at 10.4%. In addition, the PSCW approved escrow accounting treatment for the Treasury Grant. The PSCW also determined the construction costs for the ERGS units were prudently incurred, and it approved the recovery of the majority of these costs in rates.

Wisconsin Gas LLC

2015 Wisconsin 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.

2013 Wisconsin Rate Order

In March 2012, WG initiated a rate proceeding with the PSCW. In December 2012, the PSCW approved a rate decrease of approximately $34.0 million (-5.5%) for WG’s natural gas customers in 2013, with no rate adjustment in 2014. The WG rates reflected a $43.8 million reduction in bad debt expense. The rate adjustments were effective January 1, 2013, and the authorized ROE for WG remained at 10.5%.

Wisconsin Public Service Corporation

2016 Wisconsin 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 to 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, future SSR payments will continue to be 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 current 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. The amounts deferred related to these items as of December 31, 2016, were not material.

2015 Wisconsin 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 10.20% 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 2015 rates, WPS refunded approximately $4.0 million to customers related to 2013 decoupling over-collections compared with refunding approximately $13.0 million to customers in 2014 rates related to 2012 decoupling over-collections. Absent these adjustments for electric fuel costs and decoupling refunds, WPS would have realized an electric rate decrease. 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 18, 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. In 2015 rates, WPS refunded approximately $8.0 million to customers related to 2013 decoupling over-collections compared with recovering approximately $8.0 million from customers in 2014 rates related to 2012 decoupling under-collections. Absent the adjustment for decoupling refunds to and collections from customers, WPS would have realized a retail natural gas rate increase.

2015 Michigan 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 will discontinue the deferral of Fox Energy Center costs and will begin 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 are now applicable to UMERC. UMERC will not seek an increase to legacy WPS retail electric base rates that would become effective prior to January 1, 2018.

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.

Illinois Investigations

In March 2015, the ICC opened a docket, naming PGL as respondent, to investigate the veracity of certain allegations included in anonymous letters that the ICC staff received regarding PGL's SMP. This matter is still pending.

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 commenced in January 2016 and were completed in March 2016. The ICC staff submitted a report on the workshop process in May 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including what the target end date for the program should be. This proceeding is expected to result in a final order by the ICC in 2017. We are currently unable to determine what, if any, long-term impact there will be on PGL's SMP.

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, PGL recovers a return on certain investments and depreciation expense through the Qualifying Infrastructure Plant rider, and accordingly, such costs are not subject to PGL's rate order.

PGL's Qualifying Infrastructure Plant rider allows for the recovery of costs incurred related to investments in qualifying infrastructure plant. This rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudence. No schedule has been set for the 2015 reconciliation. The ALJ has placed the 2014 reconciliation on stay, pending resolution of several open matters related to PGL's SMP. Although schedules have not been set for the reconciliations, discovery has continued for both the 2014 and 2015 reconciliations. As of December 31, 2016, there can be no assurance that all costs incurred under the Qualifying Infrastructure Plant rider will be recoverable.

Minnesota Energy Resources Corporation

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, which is expected to be effective in the first quarter of 2017. The order authorized a retail natural gas rate increase of $6.8 million (3.0%). The rates reflect 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 currently authorized decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, as of December 31, 2016, we estimate that $3.0 million will be refunded to MERC's customers during 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. A decoupling mechanism with a 10% cap remains in effect for MERC's 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

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 it 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 the Tilden Mining Company (Tilden) under which it will purchase electric power from UMERC for its iron ore mine for 20 years The agreement also calls for UMERC to construct and operate approximately 180 MW of natural gas-fired generation located in the Upper Peninsula of Michigan. On January 30, 2017, UMERC filed an application with the MPSC for a certificate of necessity to begin construction of the proposed generation. The estimated cost of this project is approximately $265 million ($275 million with AFUDC), 50% of which is expected to be recovered from Tilden, with the remaining 50% expected to be recovered from utility customers located in the Upper Peninsula of Michigan. Subject to regulatory approval of both the agreement with Tilden and the construction of the proposed generation, 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.

NOTE 23—OTHER INCOME, NET

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

(in millions)	2016	2015	2014
AFUDC – Equity	**$ 25.1**	$ 20.1	$ 5.6
Gain on repurchase of notes	**23.6**	—	—
Gain on asset sales	**19.6**	22.9	7.5
Other, net	**12.5**	15.9	0.3
Other income, net	**$ 80.8**	$ 58.9	$ 13.4

NOTE 24—SEGMENT INFORMATION

At December 31, 2016, we reported six segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, and WPS, including WE's and WPS's electric and natural gas operations in the state of Michigan that were transferred to UMERC effective January 1, 2017.
- 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.
- The We Power segment includes our nonregulated entity that owns and leases generating facilities to WE.
- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the Peoples Energy, LLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. The sale of ITF was completed in the first quarter of 2016. In the second quarter of 2016, we sold certain assets of Wisvest. 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, 2016, 2015, and 2014.

	Regulated Operations								
2016 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission**	**Total Regulated Operations**	**We Power**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
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 affiliate	**—**	**—**	**—**	**146.5**	**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**	**1,476.9**	**29,917.3**	**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.

	Regulated Operations								
2015 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission**	**Total Regulated Operations**	**We Power**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
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 affiliate	—	—	—	96.1	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	1,381.0	28,875.4	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.

	Regulated Operations								
2014 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission**	**Total Regulated Operations**	**We Power**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
External revenues	$ 4,932.1	$ —	$ —	$ —	$ 4,932.1	$ 55.7	$ 9.3	$ —	$ 4,997.1
Intersegment revenues	9.2	—	—	—	9.2	383.4	—	(392.6)	—
Other operation and maintenance	1,462.7	—	—	—	1,462.7	4.4	33.0	(387.7)	1,112.4
Depreciation and amortization	323.2	—	—	—	323.2	66.7	1.5	—	391.4
Operating income (loss)	770.2	—	—	—	770.2	368.0	(26.1)	—	1,112.1
Equity in earnings of transmission affiliate	—	—	—	66.0	66.0	—	—	—	66.0
Interest expense	127.6	—	—	—	127.6	64.6	48.8	(0.7)	240.3
Capital expenditures	715.0	—	—	—	715.0	41.0	5.2	—	761.2
Total assets *	14,403.8	—	—	424.1	14,827.9	2,789.9	253.3	(2,966.1)	14,905.0

* Total assets at December 31, 2014 reflect an elimination of $2,172.9 million for all lease activity between We Power and WE.

NOTE 25—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2016					
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**
2015					
Operating revenues	$ 1,387.9	$ 991.2	$ 1,698.7	$ 1,848.3	$ 5,926.1
Operating income	358.8	165.8	345.7	380.2	1,250.5
Net income attributed to common shareholders	195.8	80.9	182.5	179.3	638.5
Earnings per share *					
Basic	$ 0.87	$ 0.36	$ 0.58	$ 0.57	$ 2.36
Diluted	0.86	0.35	0.58	0.57	2.34

* Earnings per share for the individual quarters do 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.

Due to various factors, including the acquisition of Integrys on June 29, 2015, the quarterly results of operations are not necessarily comparable.

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 intend to adopt this standard for interim and annual periods beginning January 1, 2018, as required, and plan to use the modified retrospective method of adoption. This method will result in a cumulative-effect adjustment that will be recorded on the balance sheet as of the beginning of 2018, as if the standard had always been in effect. Disclosures in 2018 will include a reconciliation of results under the new revenue guidance compared with what would have been reported in 2018 under the old revenue recognition guidance in order to help facilitate comparability with the prior periods.

We are currently reviewing our contracts with customers and related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. We consider tariff sales at our regulated utilities, excluding the revenue component related to alternative revenue programs, to be in the scope of the new standard. We have evaluated the nature of these revenues and do not expect that there will be a significant shift in the timing or pattern of revenue recognition for such sales. However, in our evaluation, we are also monitoring unresolved implementation issues for our industry, including the impacts of the new guidance on our ability to recognize revenue for certain contracts where collectability is uncertain and the accounting for contributions in aid of construction (CIAC). We currently account for CIAC funds received from customers and/or developers outside of revenue, as a reduction to property, plant, and equipment. The final resolution of these issues could impact our current accounting policies and revenue recognition.

Classification and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Classification and Measurement of Financial Assets and Liabilities. This guidance is effective for fiscal years and interim periods beginning after December 15, 2017, and will be recorded with a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective. 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. We are currently assessing the effects this guidance may have 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.

Stock-Based Compensation

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Under this ASU, all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement, the tax effects of exercised or vested awards are treated as discrete items in the reporting period in which they occur, and excess tax benefits are recognized in the current period regardless of whether the benefit reduces taxes payable. On the cash flow statement, excess tax benefits are classified along with other income tax cash flows as an operating activity, and cash paid by an employer when directly withholding shares for tax purposes is classified as a financing activity. We adopted this guidance effective January 1, 2017, and do not believe it will have a significant impact 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. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, and will be applied using a retrospective transition method. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. We are currently assessing the effects this guidance may have on our financial statements.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, Restricted Cash. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. 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. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Milwaukee, Wisconsin

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of WEC Energy Group Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated income statements, statements of comprehensive income, statements of equity, and statements of cash flows for each of the three years in the period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of WEC Energy Group, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, 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), the Company's internal control over financial reporting as of December 31, 2016, based on the 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, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 28, 2017

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Milwaukee, Wisconsin

We have audited the internal control over financial reporting of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 28, 2017 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 28, 2017

INTERNAL CONTROL OVER FINANCIAL REPORTING

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, 2016.

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.

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 Page F-91.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in our internal control over financial reporting during the fourth quarter of 2016 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

As of or for Year Ended December 31 ***(in millions, except per share information)***	**2016**	**2015 ***	**2014**	**2013**	**2012**
Operating revenues	**$ 7,472.3**	$ 5,926.1	$ 4,997.1	$ 4,519.0	$ 4,246.4
Net income attributed to common shareholders	**939.0**	638.5	588.3	577.4	546.3
Total assets	**30,123.2**	29,355.2	14,905.0	14,443.2	14,163.0
Preferred stock of subsidiary	**30.4**	30.4	30.4	30.4	30.4
Long-term debt (excluding current portion)	**9,158.2**	9,124.1	4,170.7	4,347.0	4,437.1
Weighted average common shares outstanding					
Basic	**315.6**	271.1	225.6	227.6	230.2
Diluted	**316.9**	272.7	227.5	229.7	232.8
Earnings per share					
Basic	**$ 2.98**	$ 2.36	$ 2.61	$ 2.54	$ 2.37
Diluted	**$ 2.96**	$ 2.34	$ 2.59	$ 2.51	$ 2.35
Dividends per share of common stock	**$ 1.98**	$ 1.74	$ 1.56	$ 1.45	$ 1.20

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

PERFORMANCE GRAPH

The performance graph below shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2011, in each of:

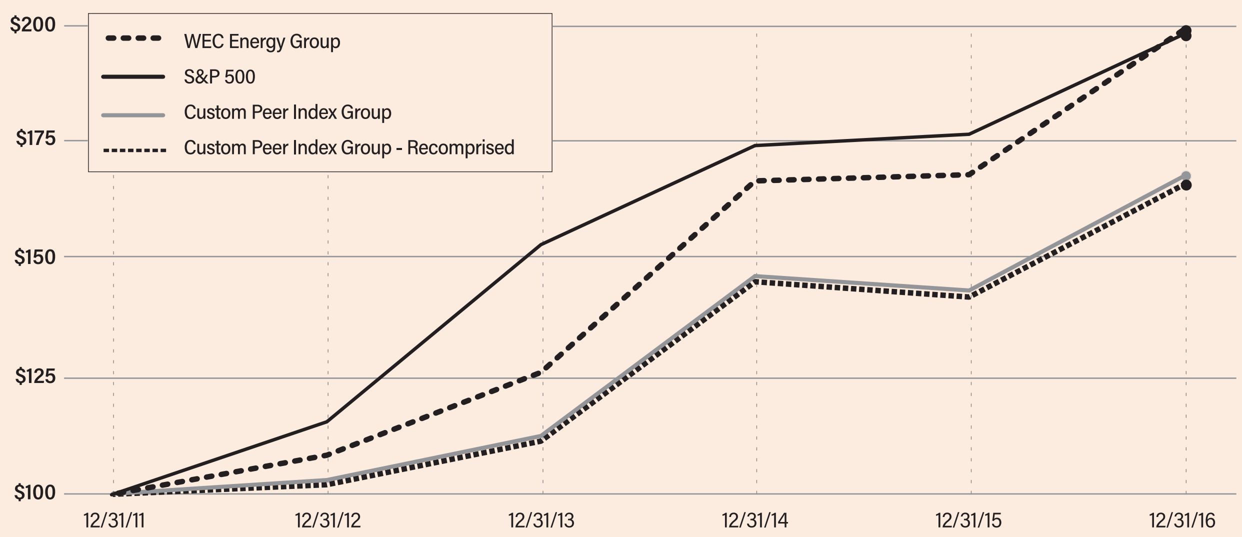
- WEC Energy Group common stock;
- a Custom Peer Group Index;
- a recomprised Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

Custom Peer Group Index. We have used the Custom Peer Group Index for peer comparison purposes because we believe the Index provided an accurate representation of our peers. The Custom Peer Group Index is a market capitalization-weighted index of companies, including WEC Energy Group, that are similar to us in terms of size and business model.

In addition to WEC Energy Group, the companies in the Custom Peer Group Index are Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; CMS Energy Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Edison International; Eversource Energy; FirstEnergy Corp.; Great Plains Energy, Inc.; NiSource Inc.; OGE Energy Corp.; PG&E Corporation; Pinnacle West Capital Corporation; SCANA Corporation; The Southern Company; Westar Energy, Inc.; and Xcel Energy Inc.

Custom Peer Group Index – Recomprised. In May 2016, Great Plains Energy, Inc. announced it had entered into an agreement to purchase Westar Energy, Inc. Therefore, in December 2016, we recomprised our Custom Peer Group to remove Westar Energy, Inc. We believe the Custom Peer Group Index, as recomprised, continues to be made up of companies that are similar to us in terms of business model and long-term strategies.

Five-Year Cumulative Return



Value of Investment at Year-End

	12/31/11	12/31/12	12/31/13	12/31/14	12/31/15	12/31/16
WEC Energy Group, Inc.	$100	$108.91	$126.47	$167.05	$168.37	$199.03
Custom Peer Group Index	$100	$102.68	$112.03	$145.91	$142.86	$167.03
Custom Peer Group Index - Recomprised	$100	$102.66	$111.89	$145.68	$142.43	$166.01
S&P 500	$100	$115.99	$153.54	$174.54	$176.94	$198.09

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of January 31, 2017, based upon the number of WEC Energy Group stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 55,000 registered stockholders.

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 11, Common Equity.

On January 19, 2017, the Board of Directors increased the quarterly dividend to $0.5200 per share effective with the first quarter of 2017 dividend payment, which equates to an annual dividend of $2.08 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.

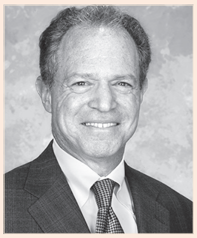
Range of WEC Energy Group Common Stock Prices and Dividends

	2016			2015		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
First	$ 60.16	$ 50.44	$ 0.4950	$ 58.01	$ 47.51	$ 0.4225
Second	$ 65.30	$ 55.46	0.4950	$ 51.54	$ 44.93	0.4225
Third	$ 66.10	$ 59.03	0.4950	$ 52.29	$ 44.97	0.4404
Fourth	$ 60.13	$ 53.66	0.4950	$ 53.88	$ 47.98	0.4575
Annual	$ 66.10	$ 50.44	$ 1.9800	$ 58.01	$ 44.93	$ 1.7429

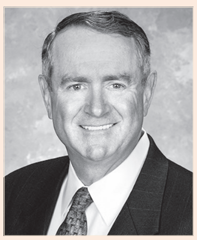
BOARD OF DIRECTORS

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.

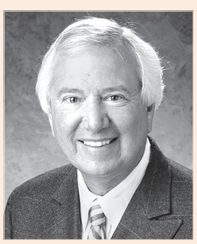


William J. Brodsky
Director since 2015.
Chairman of the Board from May 2014 to February 28, 2017 of CBOE Holdings, Inc., which is the holding company for the Chicago Board Options Exchange and CBOE Futures Exchange.



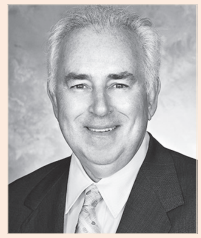
Albert J. Budney, Jr.
Director since 2015.
Retired President and Director of Niagara Mohawk Holdings, Inc., a holding company that distributes electricity in areas of New York through its utility subsidiaries.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the financial markets, business management, and global economics.



Curt S. Culver
Director since 2004.
Non-Executive Chairman of the Board of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting, and governance matters.



Paul W. Jones
Director since 2015.
Retired Executive Chairman and Chief Executive Officer of A.O. Smith Corporation, a leading manufacturer of residential and commercial water heaters and boilers. Non-Executive Chairman of Rexnord Corporation.

Gale E. Klappa
Director since 2003.
Non-Executive Chairman of the Board of WEC Energy Group, Inc.

Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a leading manufacturer of electric motors, mechanical and electrical motion controls, and power generation products.

Allen L. Leverett
Director since 2016.
President and Chief Executive Officer of WEC Energy Group, Inc.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity, and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2016 of WEC Energy Group's officers are listed below.

Allen L. Leverett[1] – President and Chief Executive Officer.

Robert M. Garvin[1] – Executive Vice President-External Affairs.

J. Patrick Keyes[1] – Executive Vice President-Strategy.

Scott J. Lauber[1] – Executive Vice President and Chief Financial Officer.

Susan H. Martin[1] – Executive Vice President, General Counsel and Corporate Secretary.

M. Beth Straka[1] – Senior Vice President-Corporate Communications and Investor Relations.

Darnell K. DeMasters – Vice President-Federal Government Affairs.

William J. Guc[1] – Vice President and Controller.

James A. Schubilske[1] – Vice President and Treasurer.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

(1) Executive Officer of WEC Energy Group as of December 31, 2016.

The following individuals are also executive officers of WEC Energy Group as of December 31, 2016:

- J. Kevin Fletcher – President of WEC Energy Group's Wisconsin segment, which includes Wisconsin Electric Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation.
- Charles R. Matthews – President of Peoples Energy, LLC, and President and Chief Executive Officer of The Peoples Gas Light and Coke Company and North Shore Gas Company.
- Tom Metcalfe – Executive Vice President-Generation of Wisconsin Electric Power Company and Wisconsin Public Service Corporation.
- Joan M. Shafer – Executive Vice President-Human Resources and Organizational Effectiveness of WEC Energy Group's Wisconsin utility subsidiaries.

Stockholder Information

ACCOUNT INFORMATION

- Visit **www.computershare.com/investor**. WEC Energy Group's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program from Computershare. eDelivery also provides electronic delivery of your annual meeting materials.

- Write to:
  WEC Energy Group
  c/o Computershare
  P.O. Box 30170
  College Station, TX 77842-3170

- If sending overnight correspondence, mail to:
  WEC Energy Group
  c/o Computershare
  211 Quality Circle, Suite 210
  College Station, TX 77845

- Call Computershare at **800-558-9663**. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold WEC Energy Group stock in brokerage accounts should contact their brokerage firm for account information.

STOCK PURCHASE PLAN

WEC Energy Group's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the Prospectus and enroll, go to **wecenergygroup.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by Prospectus.

DIVIDENDS

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Please contact Computershare to request an authorization form.

INTERNET ACCESS HELPS REDUCE COSTS

You may access **wecenergygroup.com** for the latest information about the company. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

ANNUAL CERTIFICATIONS

WEC Energy Group has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2016. The certification of WEC Energy Group's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2017 Annual Meeting of Stockholders. Last year, we filed this certification on June 3, 2016.

CORPORATE RESPONSIBILITY

WEC Energy Group is committed to corporate responsibility and sustainable business practices — aligning our policies and practices with the needs of key stakeholders, and managing risk while accounting for the company's economic, environmental and social impacts. For additional information, visit **www.wecenergygroup.com/csr**.

WEC Energy Group

WEC Energy Group

231 W. MICHIGAN ST.

P.O. BOX 1331

MILWAUKEE, WI 53201

414-221-2345

wecenergygroup.com

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