WEC ENERGY GROUP, INC.
Form 10-K
February 26, 2016

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

OR

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

For the transition period from ________________ to ___________________

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	New York Stock Exchange

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

None

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

Yes [X] No [ ]

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

Yes [ ] No [X]

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

Yes [X]   No [ ]

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

Yes [X]   No [ ]

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

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ]

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ]   No [X]

The aggregate market value of the common stock of WEC Energy Group, Inc. held by non-affiliates was $14.2 billion based upon the reported closing price of such securities as of June 30, 2015.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2016):

Common Stock, $.01 par value, 315,652,119 shares outstanding

Documents incorporated by reference:

Portions of WEC Energy Group, Inc.'s Definitive Proxy Statement on Schedule 14A for its Annual Meeting of Stockholders, to be held on May 5, 2016, are incorporated by reference into Part III hereof.

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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
WBS	WEC Business Services, LLC
We Power	W.E. Power, LLC
WECC	Wisconsin Energy Capital Corporation
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Wispark	Wispark LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation
Certain Assets	
MCPP	Milwaukee County Power Plant
OC 1	Oak Creek Expansion Unit 1
OC 2	Oak Creek Expansion Unit 2
PIPP	Presque Isle Power Plant
PSGS	Paris Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
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
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
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollutant Discharge Elimination System
Measurements	
Bcf	Billion Cubic Feet
Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand Watts)
kWh	Kilowatt-hour(s)
MDth	One thousand Dekatherms
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Other Terms and Abbreviations	
ALJ	Administrative Law Judge
AMRP	Accelerated Natural Gas Main Replacement Program
ARRs	Auction Revenue Rights
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
LMP	Locational Marginal Price
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
N/A	Not Applicable

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NYMEX	New York Mercantile Exchange
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
ROE	Return on Equity
RTO	Regional Transmission Organization
SSR	System Support Resource
Treasury Grant	Section 1603 Renewable Energy Treasury Grant

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements may be identified by reference to a future period or periods or by the use of terms such as "anticipates," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will," or variations of these terms.

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

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

- Factors affecting utility operations such as catastrophic weather-related damage, environmental incidents, unplanned facility outages and repairs and maintenance, and electric transmission or natural gas pipeline system constraints;
- Factors affecting the demand for electricity and natural gas, including political developments, unusual weather, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;
- The timing, resolution, and impact of rate cases and negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;
- 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, including the extension of bonus depreciation, 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;

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- 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 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 terms and conditions of the governmental and regulatory approvals of the acquisition of Integrys that could reduce anticipated benefits and our ability to successfully integrate the operations of the combined company;

- 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.

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PART I

ITEM 1. BUSINESS

A. INTRODUCTION

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

For more information about our business operations, including financial and geographic information about each reportable business segment, see Note 24, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

WEC Energy Group, Inc.

We were incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. Our wholly owned subsidiaries provide regulated natural gas and electricity, as well as nonregulated renewable energy. Another subsidiary, ITF, provides CNG products and services and was recorded as held for sale as of December 31, 2015. See Note 3, Dispositions, for more information. In addition, we have an approximately 60% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2015, we had six reportable segments which are discussed below. For additional information about our reportable segments, see Note 24, Segment Information.

Acquisition

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. For additional information on this acquisition, see Note 2, Acquisition.

Available Information

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

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

B. UTILITY ENERGY OPERATIONS

Wisconsin Segment

Electric Utility Operations

For the periods presented in this Annual Report on Form 10-K, our electric utility operations included operations of Wisconsin Electric for all periods and operations for WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries. Wisconsin Electric, which is the largest electric utility in the state of Wisconsin, generates and distributes electric energy to approximately 1,140,100 customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, northern Wisconsin, and Michigan's Upper Peninsula. WPS generates and distributes electric energy to approximately 449,200 customers located in northeastern Wisconsin and Michigan's Upper Peninsula.

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Electric Utility Operating Statistics

The following table shows certain electric utility operating statistics for the past three years:

	Year Ended December 31		
	2015 (1)	2014	2013
Operating revenues (in millions)			
Residential	$1,398.5	$1,199.3	$1,208.6
Small commercial and industrial	1,234.3	1,052.9	1,048.0
Large commercial and industrial	857.6	637.0	711.9
Other	26.9	23.0	23.4
Total retail revenues	3,517.3	2,912.2	2,991.9
Wholesale	181.4	131.9	143.7
Resale	248.7	264.1	143.2
Other operating revenues	77.5	87.8	28.4
Total	4,024.9	3,396.0	3,307.2
Electric customer choice (2)	2.6	5.1	1.5
Total operating revenues	$4,027.5	$3,401.1	$3,308.7
Customers – end of year (in thousands)			
Residential	1,414.1	1,015.0	1,010.5
Small commercial and industrial	171.1	115.4	114.6
Large commercial and industrial	1.0	0.7	0.7
Other	3.1	2.5	2.6
Total customers	1,589.3	1,133.6	1,128.4
Customers – average (in thousands)	1,584.4	1,130.7	1,126.9

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

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

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail and wholesale customers and distribution sales to those customers who switched to an alternative electric supplier. In 2015, retail electric revenues accounted for 87.3% of total electric operating revenues, while wholesale (including resale) electric revenues accounted for 10.7% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Wisconsin Segment Contribution to Operating Income for information on MWh sales by customer class.

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

Our electric utilities buy and sell wholesale electric power by participating in the MISO Energy Markets. The cost of our generation offered into the MISO Energy Markets, compared to our competitors, affects how often our generating units are dispatched and how we buy and sell power. For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital

Resources – Industry Restructuring.

Large Electric Retail Customers

We provide electric utility service to a diversified base of customers in such industries as mining, paper, foundry, food products and machinery production, health services, governmental, and large retail chains. In February 2015, our largest retail electric customer, the owner of two iron ore mines located in Michigan's Upper Peninsula, returned as a customer after choosing an alternative electric supplier in September 2013. Wisconsin Electric entered into a special contract with each of the mines to provide full requirements electric service through December 31, 2019. In 2015, we deferred, and we expect to continue to defer, the margin from those sales and will apply these amounts for the benefit of Wisconsin retail electric customers in a future rate proceeding. For more information,

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see Note 23, Michigan Settlement, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Industry Restructuring.

Wholesale Customers

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. Wholesale sales accounted for 6.0%, 5.3%, and 5.9% of total electric energy sales during 2015, 2014, and 2013, respectively. Wholesale revenues accounted for 4.5%, 3.9%, and 4.3% of total electric operating revenues during 2015, 2014, and 2013, respectively.

Resale

The majority of our sales for resale are sold to one RTO, MISO, at market rates based on availability of our generation and RTO demand. Resale sales accounted for 20.9%, 18.5%, and 13.3% of total electric energy sales during 2015, 2014, and 2013, respectively. Resale revenues accounted for 6.2%, 7.8%, and 4.3% of total electric operating revenues during 2015, 2014, and 2013, respectively.

Electric Sales Growth

Our service territory experienced slightly declining weather-normalized retail electric sales in 2015 as positive customer growth was more than offset by reduced volumes related to lower use per customer. We currently forecast retail electric sales volumes, excluding the two iron ore mines, to grow at a compound annual rate of between flat and 0.5% over the next five years, assuming normal weather. In addition, we forecast associated electric peak demand, excluding the two iron ore mines, to grow at a compound annual rate of between 0.5% to 1.0% over the next five years, also assuming normal weather. The owner of the two iron ore mines has announced its intention to shut down one of the mines in 2017. The potential loss of retail electric sales associated with this mine is estimated at approximately 2% of our annual total retail electric sales.

Electric Generation and Supply Mix

Our electric supply strategy is to provide our customers with energy from plants using a diverse fuel mix that is expected to maintain a stable, reliable, and affordable supply of electricity. We supply a significant amount of electricity to our customers from power plants that we own. We supplement our internally generated power supply with long-term power purchase agreements, including the Point Beach power purchase agreement discussed in Power Purchase Commitments below, and through spot purchases in the MISO Energy Markets.

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

	Rated Capacity in MW [1]		
	2015	2014	2013
Coal	4,955	3,707	3,822
Natural gas:			
Combined cycle	1,636	1,082	1,082
Steam turbine [2]	305	118	—
Natural gas/oil peaking units [3]	1,412	962	962
Renewables [4]	269	155	155
Total rated capacity by fuel type	8,577	6,024	6,021

(1)

Rated capacity is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. We are a summer peaking electric utility, and amounts are based on expected capacity ratings for the following summer. The values were established by tests and may change slightly from year to year.

(2) The natural gas steam turbine represents the rated capacity associated with the VAPP Units, which were converted from coal to natural gas in 2014 and 2015, as well as Weston Unit 2, which was converted from coal to natural gas in 2015.

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

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

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The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, as well as estimates for 2016:

	Estimate 2016	Actual 2015	2014	2013
Company-owned generation units:				
Coal	49.6 %	51.5 %	55.2 %	53.6 %
Natural gas:				
Combined cycle	18.7 %	14.6 %	8.7 %	10.1 %
Steam turbine	0.8 %	1.2 %	0.2 %	— %
Natural gas/oil peaking units	0.1 %	0.6 %	0.2 %	0.2 %
Renewables	3.5 %	3.4 %	3.8 %	3.3 %
Total company-owned generation units	72.7 %	71.3 %	68.1 %	67.2 %
Power purchase contracts:				
Nuclear	16.6 %	20.5 %	25.4 %	27.1 %
Natural gas	2.5 %	1.4 %	2.1 %	2.1 %
Renewables	2.1 %	1.5 %	2.7 %	3.1 %
Other	2.9 %	3.5 %	0.9 %	0.5 %
Total power purchase contracts	24.1 %	26.9 %	31.1 %	32.8 %
Purchased power from MISO	3.2 %	1.8 %	0.8 %	— %
Total purchased power	27.3 %	28.7 %	31.9 %	32.8 %
Total electric utility supply	100.0 %	100.0 %	100.0 %	100.0 %

Coal-Fired Generation

Our coal-fired generation consists of nine operating plants with a rated capacity of 4,955 MW as of December 31, 2015. For more information about our operating plants, see Item 2. Properties.

Natural Gas-Fired Generation

Our natural gas-fired generation consists of nine operating plants, including peaking units, with a rated capacity of 3,173 MW as of December 31, 2015. For more information about our operating plants, see Item 2. Properties.

Oil-Fired Generation

Fuel oil is used for combustion turbines at certain of our natural gas-fired plants as well as for ignition and flame stabilization at one of our coal-fired plants. Our oil-fired generation had a rated capacity of 180 MW as of December 31, 2015. We also have natural gas-fired peaking units with a rated capacity of 1,217 MW, which have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our operating plants, see Item 2. Properties.

Renewable Generation

Hydroelectric

Our hydroelectric generating system consists of 30 operating plants with a total installed capacity of 168 MW and a rated capacity of 146 MW as of December 31, 2015. All of our hydroelectric facilities follow FERC guidelines and/or regulations.

Wind

We have six wind sites, consisting of 280 turbines, with an installed capacity of 447 MW and a rated capacity of 73 MW as of December 31, 2015.

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Biomass

We constructed a biomass-fueled power plant at a Rothschild, Wisconsin paper mill site that went into commercial operation in November 2013. Wood waste and wood shavings are used to produce a rated capacity of approximately 50 MW of electric power as well as steam to support the paper mill's operations. Fuel for the power plant is supplied by both the paper mill and through contracts with biomass suppliers.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. The PSCW has a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO has a 14.3% reserve margin requirement from January 1, 2016, through May 31, 2016, and 15.2% for the remainder of 2016. The MPSC does not have minimum guidelines for future supply reserves.

We had adequate capacity through company-owned generation units and power purchase contracts to meet the MISO calculated planning reserve margin during 2015 and expect to have adequate capacity to meet the planning reserve margin requirements during 2016. However, extremely hot weather, unexpected equipment failure or unavailability across the 15-state MISO market footprint could require us to call upon load management procedures. Load management procedures allow for the reduction of energy use through agreements with customers to directly shut off their equipment or through interruptible service, where customers agree to reduce their load in the case of an emergency interruption.

Fuel and Purchased Power Costs

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers. For more information about the fuel rule, see Item 1. Business – D. Regulation.

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

	2015	2014	2013
Coal	$25.57	$27.68	$27.97
Natural gas combined cycle	17.66	40.64	32.22
Natural gas/oil peaking units	56.99	129.83	83.95
Purchased power	43.50	47.47	43.74

We purchase coal under long-term contracts, which helps with price stability. Coal and associated transportation services have continued to see volatility in pricing due to changing domestic and world-wide demand for coal and the impacts of diesel costs, which are incorporated into fuel surcharges on rail transportation. Certain of our coal transportation contracts contain fuel cost adjustments that are tied to changes in diesel fuel and crude oil prices. Currently, diesel fuel contracts are not actively traded. Therefore, we use financial heating oil contracts to mitigate risk related to diesel fuel prices.

We purchase natural gas for our plants on the spot market from natural gas marketers, utilities, and producers, and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, as well as balancing and storage agreements, intended to support our plants' variable usage.

Wisconsin Electric and WPS both have a PSCW-approved hedging program that allows them to hedge up to 75% of their potential risks related to fuel surcharge exposure. Wisconsin Electric and WPS also have a program that allows them to hedge up to 65% and 75%, respectively, of their estimated natural gas use for electric generation in order to help manage their natural gas price risk. These hedging programs are generally implemented on a 36-month forward-looking basis. The results of all of these programs are reflected in the average costs of natural gas and purchased power.

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Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming, as well as from various other states. For 2016, approximately 78% of our total projected coal requirements of approximately 16 million tons are contracted under fixed-price contracts. See Note 18, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

The annual tonnage amounts contracted for 2016 through 2018 are as follows:

(in thousands)	Annual Tonnage
2016	13,281
2017	9,303
2018	5,153

Coal Deliveries

All of our 2016 coal requirements are expected to be shipped by our owned or leased unit trains under existing transportation agreements. The unit trains transport the coal for electric generating facilities from mines in Wyoming, Pennsylvania, and Montana. The coal is transported by train to our rail-served electric-generating facilities and to dock storage in Superior, Wisconsin, until needed by our lake vessel-served facilities. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities.

Midcontinent Independent System Operator Costs

In connection with its status as a FERC approved RTO, MISO developed and operates the MISO Energy Markets, which include its bid-based energy markets and ancillary services market. We are participants in the MISO Energy Markets. In 2013, MISO expanded its footprint to include entities in Mississippi, Arkansas, Texas, and Missouri, a region referred to as MISO South. These changes have not had a material impact on our allocation of transmission costs, and we do not expect them to have a material impact in the future. For more information on MISO, see Item 1. Business – D. Regulation.

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. As of December 31, 2015, our power purchase commitments with unaffiliated parties for the next five years is 1,432 MW per year. This amount includes 1,033 MW per year related to a long-term power purchase agreement for electricity generated by Point Beach. In addition, 234 MW per year relates to a long-term power purchase agreement under which we purchase power at a price determined monthly based on a formula tied to a natural gas price index.

Other Matters

Seasonality

Our electric utility sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. We continue to upgrade our electric distribution system, including substations, transformers, and lines, to meet the demand of our customers. Our generating plants performed as expected during the warmest periods of the summer, and all power purchase commitments under firm contract were received. During this period, Wisconsin Electric did not require public appeals for conservation, and it did not interrupt or curtail service to non-firm customers who participate in load management programs. In addition, WPS did not require any public appeals for conservation, and it did not interrupt or curtail service to non-firm customers who participate in load management programs for capacity reasons. However, WPS did have service curtailments for economic reasons.

Competition

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

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The retail electric utility market in Wisconsin is regulated by the PSCW. Retail electric customers do not have the ability to choose their electric supplier, and it is uncertain when, if ever, retail electric choice might be implemented in Wisconsin. The regulated energy industry continues to experience significant structural changes, which could eventually lead to increased competition in Wisconsin.

The retail electric utility market in Michigan remains open to competition with its retail choice program, which allows customers to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Environmental Matters

For information regarding environmental matters, especially as they relate to coal-fired generating facilities, see Note 18, Commitments and Contingencies, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Environmental Matters.

Natural Gas Utility Operations

For the periods presented in this Annual Report on Form 10-K, our Wisconsin natural gas utility operations include Wisconsin Gas's and Wisconsin Electric's natural gas operations for all periods and WPS's natural gas operations, including in the Upper Peninsula of Michigan, beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries.

We are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. We also transport customer-owned natural gas. Together our natural gas distribution utilities are the largest in Wisconsin, and we operate throughout the state, including the City of Milwaukee and surrounding areas, northeastern Wisconsin, and large areas of both central and western Wisconsin.

Natural Gas Utility Operating Statistics

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

	Year Ended December 31		
	2015 [(1)]	2014	2013
Operating revenues (in millions)			
Residential	$696.2	$925.3	$712.6
Commercial and industrial	332.8	506.0	356.1
Total retail revenues	1,029.0	1,431.3	1,068.7
Transport	62.8	54.2	50.8
Other operating revenues	30.8	10.6	(5.8)
Total	$1,122.6	$1,496.1	$1,113.7
Customers – end of year (in thousands)			
Residential	1,299.7	993.9	985.7
Commercial and industrial	123.4	93.3	92.4
Transport	2.6	1.8	1.7
Total customers	1,425.7	1,089.0	1,079.8

Customers – average (in thousands)	1,417.8	1,081.5	1,074.9

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

Natural Gas Deliveries

Our gas therm deliveries include customer-owned transported natural gas. Transported natural gas accounted for approximately 50.7% of the total volumes delivered during 2015, 42.3% during 2014, and 43.1% during 2013. Our peak daily send-out during 2015 was 18.2 million therms on January 7, 2015.

Large Natural Gas Customers

We provide natural gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include governmental, educational, food products, paper, and metal. Fuel used for Wisconsin Electric's electric generation represents our largest transportation customer. Natural gas therms delivered to Wisconsin Electric for electric generation represented 15.3%, 9.3%, and 10.4% of the total volumes delivered during 2015, 2014, and 2013, respectively.

Natural Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers. For more information on our natural gas utility supply and transportation contracts, see Note 18, Commitments and Contingencies.

Pipeline Capacity and Storage

The interstate pipelines serving Wisconsin originate in major natural gas producing areas of North America: the Oklahoma and Texas basins, western Canada, and the Rocky Mountains. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

Due to the daily and seasonal variations in natural gas usage in Wisconsin, we have also contracted for substantial underground storage capacity, primarily in Michigan. We target storage inventory levels at approximately 35% of forecasted winter demand; November through March is considered the winter season. Storage capacity, along with our natural gas purchase contracts, enables us to manage significant changes in daily demand and to optimize our overall natural gas supply and capacity costs. We generally inject natural gas into storage during the spring and summer months when demand is lower and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity during periods of peak usage than would otherwise be necessary and can purchase natural gas on a more uniform daily basis from suppliers year-round. Each of these capabilities enables us to reduce our overall costs.

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

Term Natural Gas Supply

We have contracts for firm supplies with terms of 3–7 months with suppliers for natural gas acquired in the Chicago, Illinois market hub and in the producing areas discussed above. The pricing of the term contracts is based upon first of the month indices.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Wisconsin natural gas utilities' forecasted design peak-day throughput is 30.8 million therms for the 2015 through 2016 heating season.

Secondary Market Transactions

Pipeline long-line and storage capacity and natural gas supplies under contract can be resold in secondary markets. As local distribution companies, our Wisconsin natural gas utilities must contract for capacity and supply sufficient to meet the firm peak-day demand of our customers. Peak or near peak demand days generally occur only a few times each year. The secondary markets facilitate higher utilization of contracted capacity and supply during those times when the full contracted capacity and supply are not needed by the utility, helping to mitigate the fixed costs associated with maintaining peak levels of capacity and natural gas supply. Through pre-arranged agreements and day-to-day electronic bulletin board postings, interested parties can purchase this excess capacity and supply. The proceeds from these transactions are passed through to rate payers, subject to our approved GCRMs. During 2015, we continued to participate in the secondary markets. For information on the GCRMs, see Note 1(d), Revenues and Customer Receivables.

Spot Market Natural Gas Supply

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

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Hedging Natural Gas Supply Prices

Wisconsin Electric and Wisconsin Gas have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand using a mix of NYMEX-based natural gas options and futures contracts. WPS has PSCW approval to hedge up to 67% of planned winter demand using a combination of planned withdrawals from storage and NYMEX financial instruments. These approvals allow these companies to pass 100% of the hedging costs (premiums and brokerage fees) and proceeds (gains and losses) to rate payers through their respective GCRMs. Hedge targets (volumes) are provided annually to the PSCW as part of each company's three-year natural gas supply plan and risk management filing.

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

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

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

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

Federal and state regulators continue to implement policies to bring more competition to the natural gas industry. While the natural gas utility distribution function is expected to remain a highly regulated, monopoly function, the sale of the natural gas commodity and related services are expected to remain subject to competition from third parties for large commercial and industrial customers. It remains uncertain if and when the current economic disincentives for small firm customers to choose an alternative natural gas commodity supplier may be removed such that we begin to face competition for the sale of natural gas to those customers.

Steam Utility Operations

Wisconsin Electric has a steam utility that generates, distributes, and sells steam supplied by VAPP and MCPP to customers in metropolitan Milwaukee, Wisconsin. Steam is used by customers for processing, space heating, domestic hot water, and humidification. Wisconsin Electric operates a district steam system in downtown Milwaukee and the near south side of Milwaukee, and steam is supplied to this system from VAPP. Wisconsin Electric also operates the steam production and distribution facilities of the MCPP located on the Milwaukee County Grounds in Wauwatosa, Wisconsin. In 2015, we entered into an agreement to sell the MCPP, which is expected to close during the first half of 2016.

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Steam Utility Operating Statistics

Annual sales of steam fluctuate from year to year based on system growth and variations in weather conditions. Certain sections of this Annual Report on Form 10-K combine steam operating revenues with electric operating revenues.

The following table shows certain steam utility operating statistics for the past three years:

	Year Ended December 31		
	2015	2014	2013
Operating revenues (in millions)	$41.0	$44.1	$39.6
Pounds of steam sales (in millions)	2,515	2,865	2,750
Customers – average	430	440	445

Illinois Segment

Our Illinois segment includes the natural gas utility operations of PGL and NSG. PGL and NSG, both Illinois corporations, began operations in 1855 and 1900, respectively. We acquired PGL and NSG as a result of the acquisition of Integrys on June 29, 2015. Our customers are located in Chicago and the northern suburbs of Chicago.

Illinois Utilities Operating Statistics

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

	Six Months Ended December 31, 2015
Operating revenues (in millions)	
Residential	$309.8
Commercial and industrial	50.4
Total retail revenues	360.2
Transport	97.1
Other operating revenues	46.1
Total	$503.4
Customers – end of year (in thousands)	
Residential	838.2
Commercial and industrial	46.2
Transport	107.8
Total customers	992.2
Customers – average (in thousands)	982.3

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value.

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

For more information on our natural gas utility supply and transportation contracts, see Note 18, Commitments and Contingencies.

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We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our Illinois utilities when negotiating new agreements for transportation and storage services. Our Illinois utilities further reduce their supply cost volatility through the use of financial instruments, such as commodity futures, swaps, and options as part of their hedging programs. They hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

We own a 38.3 Bcf storage field (Manlove Field in central Illinois) and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, which provides a hedge against supply cost volatility. We also own a natural gas pipeline system that connects Manlove Field to Chicago and eight major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in our regulatory rate base. We also use a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to our wholesale customers. Customers deliver natural gas to us for storage through an injection into the storage reservoir, and we return the natural gas to the customers under an agreed schedule through a withdrawal from the storage reservoir. Title to the natural gas does not transfer to us. We recognize service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

We had adequate capacity to meet all firm natural gas demand obligations during 2015 and expect to have adequate capacity to meet all firm demand obligations during 2016. Our Illinois utilities' forecasted design peak-day throughput is 25.4 million therms for the 2015 through 2016 heating season.

Accelerated Natural Gas Main Replacement Program

PGL is continuing work on the AMRP, a 20-year project that began in 2011 under which PGL is replacing approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved qualifying infrastructure plant rider, which is in effect through 2023. For information on investigations related to the AMRP, see Note 22, Regulatory Environment.

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

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

Since 2002, all our Illinois utilities' natural gas customers have had the opportunity to choose a natural gas supplier other than us. As a result, we offer natural gas transportation service to enable customers to directly manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution system to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs.

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

Other States Segment

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

Other States Utilities Operating Statistics

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

	Six Months Ended December 31, 2015
Operating revenues (in millions)	
Residential	$67.6
Commercial and industrial	38.8
Total retail revenues	106.4
Transport	11.5
Other operating revenues	31.4
Total	$149.3
Customers – end of year (in thousands)	
Residential	345.8
Commercial and industrial	33.8
Transport	23.0
Total customers	402.6
Customers – average (in thousands)	401.5

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value.

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

For more information on our natural gas utility supply and transportation contracts, see Note 18, Commitments and Contingencies.

We own a storage field (Partello in Michigan) and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, which provides a hedge against supply cost volatility. We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our other states utilities when negotiating new agreements for transportation and storage services. Our other states utilities further reduce their supply cost volatility through the use of financial instruments, such as commodity futures, swaps, and options as part of their hedging programs.

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MERC hedges up to 70% of planned winter demand using a combination of planned withdrawals from storage and NYMEX financial instruments. MGU hedges up to 20% of its planned annual purchases using NYMEX financial instruments.

Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Forecasted design peak-day throughput for our other states utilities segment is 8.2 million therms for the 2015 through 2016 heating season.

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

Although our other states utilities' rates are regulated by the MPUC and MSPC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. Many large commercial and industrial customers have the ability to switch between natural gas and alternate fuels. Due to the volatility of energy commodity prices, we have seen customers with dual fuel capability switch to alternate fuels for short periods of time, then switch back to natural gas as market rates change.

MERC commercial and industrial customers have the opportunity to choose a natural gas supplier and all MGU customers have the opportunity to choose a natural gas supplier other than us. We offer natural gas transportation service and also offer interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution systems to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Electric Transmission Segment

American Transmission Company

ATC is a regional transmission company that owns, maintains, monitors, and operates electric transmission systems in Wisconsin, Michigan, Illinois, and Minnesota. ATC is expected to provide comparable service to all customers, including Wisconsin Electric and WPS, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by the FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and

Wisconsin Electric and WPS are non-transmission owning members and customers of MISO. As of December 31, 2015, our ownership interest in ATC was approximately 60%. This increase over the December 31, 2014, ownership interest of approximately 26% was due to the acquisition of Integrys on June 29, 2015. See Note 4, Investment in American Transmission Company, for more information.

In April 2011, ATC and Duke Energy announced the creation of a joint venture, DATC, that will seek opportunities to acquire, build, own, and operate new electric transmission infrastructure in North America to address increasing demand for affordable, reliable transmission capacity. In April 2013, DATC acquired a 72% interest in California's Path 15 transmission line. DATC continues to evaluate new projects and opportunities, along with participating in the competitive bidding process on projects it considers viable. These projects are located in the service territories of several different RTOs around the country. On January 20, 2016, the FERC issued an order authorizing ATC to enter into a proposed restructuring involving the creation of three new entities: ATC Holdco, ATC Development, and ATC Development Manager, Inc. ATC’s current member owners will have the option to retain their existing

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ownership interests limited to ATC in Wisconsin and adjacent states or to exchange their current ATC ownership interests for ownership interests in ATC Holdco, which would allow them to participate in ATC's transmission business in Wisconsin and adjacent states, as well as new transmission development projects throughout the U.S.

ATC is currently named in a complaint filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Other Matters, for more information.

C. NON-UTILITY OPERATIONS

We Power Segment

We Power, through wholly owned subsidiaries, has designed and built approximately 2,350 MW of generation in Wisconsin as part of our PTF strategy. This generation is made up of capacity from the Oak Creek Expansion units, OC 1 and OC 2, which were placed in service in February 2010 and January 2011, respectively, and the PWGS units, PWGS 1 and PWGS 2, which were placed in service in July 2005 and May 2008, respectively. Two unaffiliated entities collectively own approximately 17%, or approximately 211 MW, of OC 1 and OC 2. All four of the PTF units are being leased to Wisconsin Electric under long-term leases (the Oak Creek units have 30-year leases and the PWGS units have 25-year leases). The PTF units are positioned to provide a significant portion of our future generation needs.

Our PTF strategy was designed to address Wisconsin Electric's electric supply needs by increasing the electric generating capacity in Wisconsin while allowing us to maintain a diversified fuel mix by including both new coal-fired plants and natural gas-fired plants. Because of the significant investment necessary to construct these generating units, we constructed the plants under Wisconsin's Leased Generation Law, which allows a non-utility affiliate to construct an electric generating facility and lease it to the public utility. The law allows a public utility that has entered into a lease approved by the PSCW to recover fully in its retail electric rates that portion of any payments under the lease that the PSCW has allocated to the public utility's Wisconsin retail electric service, and all other costs that are prudently incurred in the public utility's operation and maintenance of the electric generating facility allocated to the utility's Wisconsin retail electric service. In addition, the PSCW may not modify or terminate a lease it has approved under the Leased Generation Law except as specifically provided in the lease or the PSCW's order approving the lease. This law effectively created regulatory certainty in light of the significant investment being made to construct the units. All four PTF units were constructed under leases approved by the PSCW.

We are recovering our costs of the PTF units, including subsequent capital additions, through lease payments that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the MPSC, and the FERC. Under the lease terms, our return is calculated using a 12.7% ROE and the equity ratio is assumed to be 55% for the Oak Creek units and 53% for the PWGS units.
For additional background information on our PTF strategy, see Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity and Capital Resources – Power the Future in Item 7. of our Annual Report on Form 10-K for the year ended December 31, 2007.

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 $72.7 million in real estate holdings at December 31, 2015. Wispark has developed several business parks and other commercial real estate projects, primarily in southeastern Wisconsin.

Wisvest was originally formed to develop, own, and operate electric generating facilities and to invest in other energy-related entities. However, Wisvest discontinued its development activity several years ago. At December 31, 2015, Wisvest's only operating asset and investment was Wisvest Thermal Energy Services, which provides chilled water services to the Milwaukee Regional Medical Center. During 2015, we entered into an agreement to sell the MCPP, including Wisvest Thermal Energy Services. This sale is expected to close during the first half of 2016.

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

WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated utilities. WBS also provides certain administrative and support services to our nonregulated entities.

PDL owns distributed renewable projects, primarily solar, and a natural gas-fired cogeneration facility in Wisconsin known as the Combined Locks Energy Center. PDL's natural gas-fired facility is subject to market price volatility and is dispatched to produce energy only when it is economical to do so. PDL's renewable energy facilities rely on renewable resources, such as solar irradiance or landfill gas. There is no market price risk associated with the fuel supply of these facilities. However, production at these facilities can be intermittent due to the availability of the renewable energy resource.

ITF designs, builds, maintains, owns, and operates CNG fueling stations in multiple states. In addition, ITF manufactures its own compressor package, which includes a proprietary method of compressing natural gas. Since ITF's operations are inconsistent with our risk profile, we entered into an agreement to sell ITF in February 2016. See Note 3, Dispositions, for more information.

D. REGULATION

We are a holding company and are subject to the requirements of the Public Utility Holding Company Act of 2005 (PUHCA 2005). We also have various subsidiaries that meet the definition of a holding company under PUHCA 2005 and are also subject to its requirements.

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

Regulated Utility Operations

In addition to the specific regulations noted above and below, our utilities are also subject to regulations, where applicable, of the EPA, the WDNR, the MDEQ, the Michigan Department of Natural Resources, the Illinois Environmental Protection Agency, the U.S. Army Corps of Engineers, the Minnesota Department of Natural Resources, and the Minnesota Pollution Control Agency.

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Rates

Our utilities' rates are regulated by the various commissions shown in the table below. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Regulated Rates	Regulatory Commission
Wisconsin Electric	
Retail electric, natural gas, and steam	PSCW
Retail electric	MPSC
Wholesale power	FERC
WPS	
Retail electric and natural gas	PSCW and MPSC
Wholesale power	FERC
Wisconsin Gas	
Retail natural gas	PSCW
PGL	
Retail natural gas	ICC
NSG	
Retail natural gas	ICC
MERC	
Retail natural gas	MPUC
MGU	
Retail natural gas	MPSC

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

Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers and our Wisconsin wholesale electric customers. Our natural gas operations operate under GCRMs as approved by their respective state regulator. Generally, the GCRMs allow for a dollar-for-dollar recovery of prudently incurred natural gas costs.

For a summary of the significant mechanisms our utility subsidiaries had in place in 2015 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts, see Note 1(d), Revenues and Customer Receivables.

In May 2015, the PSCW approved the acquisition of Integrys on the condition that Wisconsin Electric and Wisconsin Gas will be subject to an earnings sharing mechanism for three years beginning January 1, 2016. See Note 2, Acquisition, for more information on this earnings sharing mechanism.

For information on how rates are set for our regulated entities, see Note 22, Regulatory Environment. Orders from our respective regulators can be viewed at the following websites:

Regulatory Commission	Website
PSCW	https://psc.wi.gov/
ICC	https://www.icc.illinois.gov/

MPSC	http://www.michigan.gov/mpsc/
MPUC	http://mn.gov/puc/
FERC	http://www.ferc.gov/

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

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

	2015			2014			2013		
(in millions)	Amount	Percent		Amount	Percent		Amount	Percent	
Electric [1]									
Wisconsin	$3,374.9	83.0	%	$2,934.0	85.2	%	$2,914.4	87.0	%
Michigan	173.1	4.3	%	58.8	1.7	%	147.0	4.4	%
FERC – Wholesale	429.1	10.5	%	396.0	11.5	%	286.9	8.6	%
FERC – SSR [2]	91.4	2.2	%	56.4	1.6	%	—	—	%
Total	4,068.5	100.0	%	3,445.2	100.0	%	3,348.3	100.0	%
Natural Gas [1]									
Wisconsin	1,121.3	63.2	%	1,496.1	100.0	%	1,113.7	100.0	%
Illinois	503.4	28.4	%	—	—	%	—	—	%
Minnesota	98.3	5.5	%	—	—	%	—	—	%
Michigan	52.3	2.9	%	—	—	%	—	—	%
Total	1,775.3	100.0	%	1,496.1	100.0	%	1,113.7	100.0	%
Total utility operating revenues	$5,843.8			$4,941.3			$4,462.0		

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

(2) See Note 22, Regulatory Environment, for more information regarding SSR revenues.

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the MISO Energy Markets, which include the bid-based energy markets and an ancillary services market. We previously self-provided both regulation reserves and contingency reserves. In the MISO ancillary services market, we buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market has been able to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market has enabled MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

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

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO, and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2015, through May 31, 2016. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

Beginning June 1, 2013, MISO instituted an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources could be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. Our capacity requirements during 2015 were primarily fulfilled using our own capacity resources.

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Other Electric Regulations

Wisconsin Electric and WPS are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act amended the Federal Power Act in 2005 to, among other things, make electric utility industry consolidation more feasible, authorize the FERC to review proposed mergers and the acquisition of generation facilities, change the FERC regulatory scheme applicable to qualifying cogeneration facilities, and modify certain other aspects of energy regulations and Federal tax policies applicable to us. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by the FERC, which established mandatory electric reliability standards and which has the authority to levy monetary sanctions for failure to comply with these standards.

Wisconsin Electric and WPS are subject to Act 141 in Wisconsin and Public Act 295 in Michigan, which contain certain minimum requirements for renewable energy generation. See Note 18, Commitments and Contingencies, for more information.

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

Other Natural Gas Regulations

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

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

Non-Utility Operations

We Power, through wholly owned subsidiaries, constructed the new generating capacity in our PTF strategy. These facilities are being leased on a long-term basis to Wisconsin Electric. Environmental permits necessary for operating the facilities are the responsibility of the operating entity, Wisconsin Electric. We Power received determinations from the FERC that upon the transfer of the facilities by lease to Wisconsin Electric, We Power's subsidiaries would not be deemed public utilities under the Federal Power Act and thus would not be subject to the FERC's jurisdiction.

E. ENVIRONMENTAL COMPLIANCE

Our operations are subject to extensive environmental regulation by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental regulations or revisions to existing laws, including for example, additional regulation of GHG emissions, coal combustion products, air emissions, or wastewater discharges, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and remediation issues for the next three years are included in the estimated capital expenditures described in Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements in Item 7. For a discussion of matters related to certain solid waste and coal combustion product landfills, manufactured gas plant sites, and air and water quality, see Note 18, Commitments and Contingencies, and Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Environmental Matters in Item 7.

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F. EMPLOYEES

As of December 31, 2015, we had the following number of employees:

	Total Employees	Number of Full-Time Employees
Wisconsin Electric	3,653	3,551
WPS	1,329	1,267
Wisconsin Gas	426	415
PGL	1,339	1,337
NSG	167	166
MERC	216	213
MGU	159	156
WBS	1,043	* 998
ITF	108	105
Other	3	3
Total employees	8,443	8,211

* Effective January 1, 2016, approximately 500 employees were transferred from Wisconsin Electric and Wisconsin Gas into WBS.

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As of December 31, 2015, we had employees represented under labor agreements with the following bargaining units:

	Number of Employees	Expiration Date of Current Labor Agreement
Wisconsin Electric		
Local 2150 of International Brotherhood of Electrical Workers, AFL-CIO	1,679	August 15, 2017
Local 420 of International Union of Operating Engineers, AFL-CIO	489	September 30, 2017
Local 2006 Unit 1 of United Steel Workers of America, AFL-CIO	123	April 30, 2017
Local 510 of International Brotherhood of Electrical Workers, AFL-CIO	105	October 31, 2016
Total Wisconsin Electric	2,396	
WPS		
Local 420 of International Union of Operating Engineers, AFL-CIO	917	October 15, 2016
Wisconsin Gas		
Local 2150 of International Brotherhood of Electrical Workers, AFL-CIO	91	August 15, 2017
Local 2006 Unit 1 of United Steel Workers of America, AFL-CIO	191	April 30, 2017
Local 2006 Unit 3 of United Steel Workers of America, AFL-CIO	3	February 29, 2016
Total Wisconsin Gas	285	
PGL		
Local 18007 of Utility Workers Union of America, AFL-CIO	955	April 30, 2018
NSG		
Local 2285 of International Brotherhood of Electrical Workers, AFL CIO	121	June 30, 2019
MERC		
Local 31 of International Brotherhood of Electrical Workers, AFL CIO	39	May 31, 2016
MGU		
Local 12295 of United Steelworkers of America, AFL-CIO CLC	77	January 15, 2017
Local 417 of Utility Workers Union of America, AFL-CIO *	31	February 15, 2016
Total MGU	108	
Total represented employees	4,821	

* MGU entered into a labor agreement with Local 417 of Utility Workers Union of America AFL-CIO, which became effective February 16, 2016. The agreement expires on February 15, 2019.

ITEM 1A. RISK FACTORS

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

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation.

We are subject to significant state, local, and federal governmental regulation, including regulation by the various utility commissions in the states where we serve customers. This regulation significantly influences our operating environment and may affect our ability to recover costs from utility customers. Many aspects of our operations are regulated, including, but not limited to: the rates we charge our retail electric, natural gas, and steam customers; wholesale power service practices; electric reliability requirements and accounting; participation in the interstate natural gas pipeline capacity market; standards of service; issuance of securities; short-term debt obligations; construction and operation of facilities; transactions with affiliates; and billing practices. Our significant level of regulation imposes restrictions on our operations and causes us to incur substantial compliance costs. Failure to comply with any applicable rules or regulations may lead to customer refunds, penalties, and other payments, which could materially and adversely affect our results of operations and financial condition.

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

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

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

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

Our operations are subject to numerous federal and state environmental laws and regulations. These laws and regulations govern, among other things, air emissions (including CO_2, methane, mercury, SO_2, and NOx), water quality, wastewater discharges, and management of hazardous, toxic, and solid wastes and substances. We incur significant costs to comply with these environmental requirements, including costs associated with the installation of pollution control equipment, environmental monitoring, emissions fees, and permits at our facilities. In addition, if we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines.

The EPA has adopted and has implemented (or is in the process of implementing) regulations governing the emission of NOx, SO_2, fine particulate matter, mercury, and other air pollutants under the CAA through the NAAQS, the MATS rule, the Clean Power Plan,

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the CSAPR, and other air quality regulations. In addition, the EPA has finalized regulations under the Clean Water Act that govern cooling water intake structures at our power plants and revised the effluent guidelines for steam electric generating plants. The EPA has also adopted a final rule that would expand traditional federal jurisdiction over navigable waters and related wetlands for permitting and other regulatory matters; however, this rule has been stayed. We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations. Several environmental regulations were either finalized or implemented during 2015, and there is still uncertainty as to what capital expenditures or additional costs may ultimately be required to comply with these regulations.

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

As a result, certain of our coal-fired electric generating facilities may become uneconomical to maintain and operate, which could result in some of these units being retired early or converted to an alternative type of fuel. If generation facility owners in the Midwest, including us, are forced to retire a significant number of older coal-fired generation facilities, a potential reduction in the region's capacity reserve margin below acceptable risk levels may result. This could impair the reliability of the grid in the Midwest, particularly during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

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

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

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by environmental impacts and alleged exposure to hazardous materials have become more frequent. In addition to claims relating to our current facilities, we may also be subject to potential liability in connection with the environmental condition of facilities that we previously owned and operated, regardless of whether the liabilities arose before, during, or after the time we owned or operated these facilities. If we fail to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a significant adverse effect on our results of operations and financial condition.

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

Federal, state, regional, and international authorities have undertaken efforts to limit GHG emissions. In 2015, the EPA issued the Clean Power Plan, which is a final rule that regulates GHG emissions from existing generating units, as well as a proposed federal plan as an alternative to state compliance plans. The EPA also issued final performance standards for modified and reconstructed generating units, as well as for new fossil-fueled power plants. Under the Clean Power Plan, states are required to submit compliance plans as early as September 2016 to achieve state-specific GHG emission reductions by 2030. If Wisconsin or Michigan determines not to file a state compliance plan, we may be required to comply with the federal plan, which could result in more significant

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compliance costs than a state compliance plan. We are continuing to analyze the final rule and to work with other stakeholders to determine how to implement the Clean Power Plan and the potential impacts to our operations. In October 2015, 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 United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals) denied the stay request, but on February 9, 2016, the United States Supreme Court (Supreme Court) stayed the effectiveness of the rule until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that review is sought, at the Supreme Court. Therefore, it is unlikely that states will move forward on the development of the state plans until the litigation is complete. Any state or federal compliance plans that are developed could be subject to change based upon the outcome of this litigation. In addition, on February 15, 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 rule could result in significant additional compliance costs, including capital expenditures, and impact how we operate our existing fossil-fueled power plants and biomass facility, all of which could have a material adverse impact on our operating costs.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with the Clean Power Plan or that cost recovery will not be delayed or otherwise conditioned. The Clean Power Plan and any other related regulations that may be adopted in the future, either at the federal or state level, may cause our environmental compliance spending over the next several years to differ materially from the amounts currently estimated. These regulations could have a material adverse impact on our electric generation and natural gas distribution operations, could make some of our electric generating units uneconomic to maintain or operate, and could affect unit retirement and replacement decisions. These regulations could also adversely affect our future results of operations, cash flows, and financial condition.

In addition, our natural gas delivery systems may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair of natural gas delivery systems. Fugitive gas typically vents to the atmosphere and consists primarily of methane. CO_2 is also a byproduct of natural gas consumption. As a result, future legislation to regulate GHG emissions could increase the price of natural gas, restrict the use of natural gas, and adversely affect our ability to operate our natural gas facilities. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could reduce natural gas demand.

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

Our electric utilities are subject to mandatory reliability and critical infrastructure protection standards established by the North American Electric Reliability Corporation and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. If our electric utilities were ever found to be in noncompliance with the mandatory reliability standards, they could be subject to sanctions, including substantial monetary penalties.

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

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

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

Risks Related to the Operation of Our Business

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

Our financial performance depends on the successful operation of our electric generation and natural gas and electric distribution facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or

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processes. Potential breakdown or failure may occur due to severe weather; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, pandemic health events, etc.); significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist attacks; or cyber security threats. Any of these events could lead to substantial financial losses.

Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems. Unplanned outages at our power plants may reduce our revenues or cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses.

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

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

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

- Fluctuations in customer growth and general economic conditions in our service areas. Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including job losses, decreases in income, and business closings. Our electric and natural gas utilities are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn or disruption of financial markets could adversely affect the financial condition of our customers and demand for their products. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- Weather conditions. Demand for electricity is greater in the summer and winter months associated with cooling and heating. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the summer cooling season and during the winter heating season may result in lower revenues and net income.
- Our customers' continued focus on energy conservation and ability to meet their own energy needs. Customers could voluntarily reduce their consumption of energy in response to decreases in their disposable income, increases in energy prices, and individual conservation efforts through the use of more energy efficient technologies. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how consumers use energy. In addition, several states, including Wisconsin and Michigan, have adopted energy efficiency targets to reduce energy consumption by certain dates.

As part of our planning process, we estimate the impacts of changes in customer growth and general economic conditions, weather, and customer energy conservation efforts, but risks still remain. Any of these matters, as well as any regulatory delay in adjusting rates as a result of reduced sales from effective conservation measures or the adoption of new technologies, could adversely impact our results of operations and financial condition.

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

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage, and other projects, including projects for environmental compliance. In addition, WBS has various capital projects that are primarily related to the development of software applications used to support our utilities.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. These risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; other governmental actions; continued public and policymaker support for such projects; and events in the global economy. In addition, certain of these projects require the approval of our regulators. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, the applicable commission may deem the additional capital costs as imprudent and disallow recovery of them through rates.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

In 2015, the ICC and the Attorney General of Illinois initiated investigations into our AMRP capital project. Since the investigations are ongoing, it is too early to determine, what effect, if any, the investigations will have on the AMRP.

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

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, and energy efficiency. We generate power at central station power plants to achieve economies of scale and produce power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells, which have become more cost competitive. It is possible that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station power production. If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities could be reduced. Advances in technology could also change the channels through which our electric customers purchase or use power, which could reduce our sales and revenues or increase our expenses.

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

We face the risk of terrorist and cyber intrusions, both threatened and actual, against our generation facilities, electric and natural gas distribution infrastructure, our information and technology systems, and network infrastructure, including that of third parties on which we rely, any of which could result in a full or partial disruption of our ability to generate, transmit, purchase, or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations, financial condition, and cash flows.

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

We face on-going threats to our assets and technology systems. Despite the implementation of strong security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to human error or physical or cyber intrusions. If our assets or systems were to fail, be physically damaged, or be breached and were not recovered in a timely manner, we may be unable to perform critical business functions, and sensitive and other data could be compromised.

Our business requires the collection and retention of personally identifiable information of our customers, stockholders, and employees, who expect that we will adequately protect such information. Security breaches may expose us to a risk of loss or misuse of confidential and proprietary information. A significant theft, loss, or fraudulent use of personally identifiable information may lead to potentially large costs to notify and protect the impacted persons, and/or could cause us to become subject to significant litigation, costs, liability, fines, or penalties, any of which could materially and adversely impact our results of operations as well as our reputation with customers, stockholders and regulators, among others. In addition, we may be required to incur significant costs associated with governmental actions in response to such intrusions or to strengthen our information and electronic control systems. We may also need to obtain additional insurance coverage related to the threat of such intrusions.

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The costs of repairing damage to our facilities, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Transporting, distributing, and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

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

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

As a holding company with no operations of our own, our ability to meet our financial obligations and pay dividends on our common stock is dependent upon the ability of our subsidiaries to pay amounts to us, whether through dividends or other payments. Our subsidiaries are separate legal entities that have no obligation to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to pay amounts to us depends on their earnings, cash flows, capital requirements, and general financial condition, as well as regulatory limitations. Prior to distributing cash to us, our subsidiaries have financial obligations that must be satisfied, including, among others, debt service and preferred stock dividends. In addition, each subsidiary's ability to pay amounts to us depends on any statutory, regulatory, and/or contractual restrictions and limitations applicable to such subsidiary, which may include requirements to maintain specified levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

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

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

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

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

We have entered into several power purchase agreements with non-affiliated companies, and continue to look for additional opportunities to enter into these agreements. Revenues are dependent on the continued performance by the purchasers of their obligations under the power purchase agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more purchasers could fail to perform their obligations under the power purchase agreements. If this were to occur, we would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase agreement would be reallocated among our retail customers. To the extent there is any regulatory delay in adjusting rates, a customer default under a power purchase agreement could have a negative impact on our results of operations and cash flows.

Our revenues could be negatively impacted by competitive activity in the wholesale electricity markets.

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

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

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

Risks Related to Economic and Market Volatility

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

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates. In addition, we rely on committed bank credit agreements as back-up liquidity, which allows us to access the low cost commercial paper markets.

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

- A rating downgrade;
- An economic downturn or uncertainty;
- Prevailing market conditions;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

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

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

There are a number of factors that impact our and our subsidiaries' credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We or any of our subsidiaries could experience a downgrade in ratings if the rating agencies determine that the level of business or financial risk of us, our utilities, or the utility industry has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings.

Any downgrade by the rating agencies could:

- Increase borrowing costs under certain existing credit facilities;
- Require the payment of higher interest rates in future financings and possibly reduce the pool of creditors;
- Decrease funding sources by limiting our or our subsidiaries' access to the commercial paper market;
- Limit the availability of adequate credit support for our subsidiaries' operations; and
- Trigger collateral requirements in various contracts.

Fluctuating commodity prices could negatively impact our electric and natural gas utility operations.

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

Our electric utilities burn natural gas in several of their electric generation plants and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. The cost of natural gas may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations affecting its accessibility.

Our Wisconsin electric utilities bear the risk for the recovery of fuel and purchased power costs within a symmetrical 2% fuel tolerance band compared to the forecast of fuel and purchased power costs established in their respective rate structures. Our natural gas utilities receive dollar-for-dollar recovery of prudently incurred natural gas costs.

Changes in commodity prices could result in:

- Higher working capital requirements, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Reduced profitability to the extent that reduced margins, increased bad debt, and interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact our competitive position;
- Reduced demand for energy, which could impact margins and operating expenses; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

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

We are dependent on coal for much of our electric generating capacity. Although we generally carry sufficient coal inventory at our generating facilities to protect against an interruption or decline in supply, there can be no assurance that the inventory levels will be adequate. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us or that we will be able to take delivery of all the coal volume contracted for. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us, or we may experience operational problems or constraints that prevent us from taking delivery. In addition, suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. Furthermore, demand for coal can impact its availability and cost. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices or we may be forced to reduce generation at our coal-fired units and replace this lost generation through additional power purchases in the MISO Energy Markets. There is no guarantee that we would be able to fully recover any increased costs in rates or that recovery would not otherwise be delayed, either of which could adversely affect our cash flows.

Our electric generation frequently exceeds our customer load. When this occurs, we generally sell the excess generation into the

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MISO Energy Markets. If we are unable to run our lower cost units, we may lose the ability to engage in these opportunity sales, which may adversely affect our results of operations.

The use of derivative contracts could result in financial losses.

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

Restructuring in the regulated energy industry could have a negative impact on our business.

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us.

Certain jurisdictions in which we operate, including Michigan and Illinois, have adopted retail choice. Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines located in the Upper Peninsula of Michigan are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer. It is uncertain whether retail choice might be implemented in Wisconsin or Minnesota.

Illinois utilities' retail customers may choose an alternative natural gas supplier. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution system to transport the natural gas to their facilities. Because we earn a distribution charge for transporting the natural gas for these customers, these arrangements have little or no impact on our net income.

FERC continues to support the existing RTOs that affect the structure of the wholesale market within these RTOs. In connection with its status as a FERC approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. The MISO Energy Markets rules require that all market participants submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes an LMP that reflects the market price for energy. As a participant in the MISO Energy Markets, we are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining stability of the transmission system. MISO also implemented an ancillary services market for operating reserves that was simultaneously co-optimized with its existing energy markets.

These market designs continue to have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the MISO Energy Markets, and the costs associated with estimated payment settlements.

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

We have significant obligations related to pension and OPEB plans. If we are unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition, or results of operations could be adversely impacted.

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

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

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

Risks Related to the Integrys Acquisition

The acquisition of Integrys may not achieve its anticipated results, and we may be unable to integrate operations as expected.

The Merger Agreement was entered into with the expectation that the acquisition would result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the acquisition is subject to a number of uncertainties, including whether the businesses of the two companies can be integrated in an efficient, effective, and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees; the disruption of ongoing businesses, processes, and systems; or inconsistencies in standards, controls, procedures, practices, policies, and compensation arrangements, any of which could adversely affect our ability to achieve the anticipated benefits of the transaction as and when expected. We may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve the anticipated benefits of the acquisition could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results, and prospects.

The acquisition may not be accretive to earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common stock.

We anticipate that the acquisition will be accretive to earnings per share in 2016, which will be the first full year following completion of the transaction. This expectation is based on preliminary estimates that are subject to change. We also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the acquisition, or may be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in our earnings per share or decrease or delay the expected accretive effect of the transaction and contribute to a decrease in the price of our common stock.

We may incur unexpected transaction fees and transaction-related costs in connection with the acquisition.

We incurred a number of expenses associated with completing the acquisition, and expect to incur additional expenses related to combining the operations of the two companies. We may incur additional unanticipated costs in the integration of the businesses. Although we expect that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses of the two companies, will offset the incremental transaction-related costs over time, we may not achieve this net benefit in the near term, or at all.

We recorded goodwill that could become impaired and adversely affect financial results.

The acquisition of Integrys was accounted for as a purchase in accordance with GAAP. Under the purchase method of accounting, the assets and liabilities acquired and assumed were recorded at their estimated fair values at the date of acquisition and added to those of legacy Wisconsin Energy Corporation. The excess of the purchase price over the estimated fair values was recorded as goodwill. As of December 31, 2015, goodwill totaled $3,023.5 million, of which $2,581.6 million is attributable to the acquisition of Integrys. We perform an analysis of our goodwill balances to test for impairment on an annual basis or whenever events occur or circumstances change that would indicate a potential for impairment. If goodwill is deemed to be impaired, we may be required to incur material non-cash charges that could materially adversely affect our results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

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

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2015:

Name	Location	Fuel	Number of Generating Units	Rated Capacity In MW (1)	
Coal-fired plants					
Columbia	Portage, WI	Coal	2	353	(2)
Edgewater	Sheboygan, WI	Coal	1	96	(2)
Milwaukee County	Wauwatosa, WI	Coal	3	7	(3)
Oak Creek Expansion	Oak Creek, WI	Coal	2	1,057	(4)
Pleasant Prairie	Pleasant Prairie, WI	Coal	2	1,188	
Presque Isle	Marquette, MI	Coal	5	344	
Pulliam	Green Bay, WI	Coal	2	212	
South Oak Creek	Oak Creek, WI	Coal	4	993	
Weston Units 3 and 4	Rothschild, WI	Coal	2	705	(2)
Total coal-fired plants			23	4,955	
Natural gas-fired plants					
Concord Combustion Turbines	Watertown, WI	Natural Gas/Oil	4	352	
De Pere Energy Center	De Pere, WI	Natural Gas/Oil	1	158	
Fox Energy Center	Wrightstown, WI	Natural Gas	3	554	
Germantown Combustion Turbines	Germantown, WI	Natural Gas/Oil	5	258	
Juneau	Adams, WI	Distillate Fuel Oil	1	—	(5)
Paris Combustion Turbines	Union Grove, WI	Natural Gas/Oil	4	352	
Port Washington Generating Station	Port Washington, WI	Natural Gas	2	1,082	(6)
Pulliam	Green Bay, WI	Natural Gas/Oil	1	78	
Valley Power Plant	Milwaukee, WI	Natural Gas	2	240	
West Marinette	Marinette, WI	Natural Gas/Oil	3	153	
Weston	Rothschild, WI	Natural Gas/Oil	3	126	
Total natural gas-fired plants			29	3,353	
Renewables					

Hydro Plants (30 in number)	WI and MI	Hydro	84	146	(7)
Rothschild Biomass Plant	Rothschild, WI	Biomass	1	50	
Blue Sky Green Field	Fond du Lac, WI	Wind	88	21	
Byron Wind Turbines	Fond du Lac, WI	Wind	2	—	
Crane Creek	Howard County, IA	Wind	66	21	
Glacier Hills	Cambria, WI	Wind	90	28	
Lincoln	Kewaunee County, WI	Wind	14	1	
Montfort Wind Energy Center	Montfort, WI	Wind	20	2	
Total renewables			365	269	
Total system			417	8,577	

(1) Based on expected capacity ratings for summer 2016, which can differ from nameplate capacity, especially on wind projects. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

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

- Wisconsin Power and Light Company, an unaffiliated utility, operates the Columbia and Edgewater units. WPS holds a 31.8% ownership interest in these facilities.
- WPS operates the Weston 4 facility and holds a 70% ownership interest in this facility. Dairyland Power Cooperative holds the remaining 30% interest.

(3) Wisconsin Electric expects to complete the sale of MCPP during the first half of 2016.

(4) This facility is jointly owned by We Power and various other utilities. The capacity indicated for the facility is equal to We Power's portion of total plant capacity based on its 83.34% ownership.

(5) Wisconsin River Power Company (WRPC) owns and operates the Juneau unit. WPS holds a 50% ownership interest in WRPC and is entitled to 50% of the total capacity from the Juneau unit.

(6) We Power owns 100% of Port Washington Generating Stations 1 and 2.

(7) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50% ownership interest in WRPC and is entitled to 50% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 8.1 MWs, and WPS's share of capacity for Petenwell is 10.2 MWs.

As of December 31, 2015, we operated approximately 40,200 pole-miles of overhead distribution lines and 31,100 miles of underground distribution cable, as well as approximately 500 distribution substations and 489,400 line transformers.

Natural Gas Facilities

At December 31, 2015, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 44,200 miles of natural gas distribution mains,
- Approximately 1,100 miles of natural gas transmission mains,
- Approximately 2.3 million natural gas lateral services,
- Approximately 500 natural gas distribution and transmission gate stations,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.3 billion-cubic-foot underground natural gas storage field located in central Illinois,
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois,
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Wisconsin,
- Peak propane air systems providing approximately 2,960 Dth per day, and
- Liquefied natural gas storage plants with a total send-out capability of 73,600 Dth per day.

Our natural gas distribution system included distribution mains and transmission mains connected to the pipeline transmission systems of ANR Pipeline Company, Guardian Pipeline L.L.C., Natural Gas Pipeline Company of America, Northern Natural Pipeline Company, Great Lakes Transmission Company, Viking Gas Transmission, and Michigan Consolidated Gas Company. Our liquefied natural gas storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

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

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

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Steam Facilities

As of December 31, 2015, the combined steam systems supplied by the VAPP and MCPP consisted of approximately 42 miles of both high pressure and low pressure steam piping, nine miles of walkable tunnels, and other pressure regulating equipment.

General

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

B. CORPORATE AND OTHER

As of December 31, 2015, the corporate and other segment facilities consisted of energy asset facilities owned by PDL and CNG fueling stations owned by ITF.

The energy asset facilities owned by PDL include a portfolio of residential solar facilities, a portfolio of commercial and industrial solar facilities, a landfill gas transportation facility, and a natural gas co-generation facility. The solar facilities consist of distributed solar projects ranging from small residential roof top systems up to commercial and industrial solar systems of 4.5 MWs in size. The total capacity of these solar projects is 27.6 MWs. The majority of the solar facilities are wholly owned by subsidiaries of PDL while one is jointly owned by PDL and Duke Energy Generation Services. PDL's portion of the jointly owned solar capacity is 0.4 MWs. The landfill gas transportation facility in Brazoria County, Texas, has 33 miles of natural gas pipeline connecting a landfill and chemical plant. The natural gas co-generation station in Combined Locks, Wisconsin, has a summer design capacity of 45.5 MWs.

The CNG fueling stations consist of 32 stations that are wholly owned and operated by ITF. Additionally, ITF operates five stations that are owned by EVO Trillium LLC, which is jointly owned by ITF and Environmental Alternative Fuels, LLC. ITF holds a 15% ownership interest in EVO Trillium LLC. The sale of these facilities is currently pending. See Note 3, Dispositions, for more information.

ITEM 3. LEGAL PROCEEDINGS

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

OTHER MATTERS

Litigation Relating to the Acquisition of Integrys

After the announcement of the acquisition, Integrys and its board of directors, along with WEC Energy Group, were named as defendants in ten separate purported class action lawsuits filed in Brown County, Wisconsin (three of the cases – Rubin v. Integrys, et al., Blachor v. Integrys, et al., and Albera v. Integrys, et al.), Milwaukee County, Wisconsin (two of the cases – Amo v. Integrys, et al. and Inman v. Integrys, et al.), Cook County, Illinois (two of the cases – Taxman v. Integrys, et al. and Curley v. Integrys, et al.), and the federal court for the Northern District of Illinois (three of the cases – Steiner v. Integrys, et al., Tri-State Joint Fund v. Integrys, et al., and Collison v. Integrys, et al.). In the Tri-State Joint Fund case, WEC Energy Group’s CEO was also named as a defendant. The cases were brought on behalf of proposed classes consisting of former shareholders of Integrys. The complaints alleged, among other things, that the Integrys board members breached their fiduciary duties by failing to maximize the value to be received by Integrys's shareholders, that WEC Energy Group aided and abetted the breaches of fiduciary duty, and that the joint proxy statement/prospectus contained material misstatements and omissions. The Brown County and Cook County cases were dismissed in favor of the Milwaukee County actions. On November 12, 2014, the parties entered into a Memorandum of Understanding which provided the basis for a complete settlement of these actions. A Stipulation of Settlement was presented to the Court in late July 2015. On December 17, 2015, the Court approved the settlement and entered a final judgment in this matter, which resulted in the complete dismissal of all remaining actions. The period to appeal the Court's order terminates on March 16, 2016.

See Note 18, Commitments and Contingencies, and Note 22, Regulatory Environment, for more information on material legal proceedings and matters related to us and our subsidiaries.

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ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, and positions of our executive officers at December 31, 2015 are listed below along with their business experience during the past five years. All officers are appointed until they resign, die, or are removed pursuant to our Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected.

Gale E. Klappa. Age 65.
- WEC Energy Group — Director since 2003. Chairman and Chief Executive Officer since May 2004. President from April 2003 to July 2013.
- Wisconsin Electric — Director since 2003. Chairman of the Board since May 2004. Chief Executive Officer since August 2003. President from August 2003 to June 2015.
- Director of Joy Global, Inc. since 2006 and Badger Meter, Inc. since 2010.

J. Kevin Fletcher. Age 57.
- Wisconsin Electric — Director and Executive Vice President - Customer Service and Operations since June 2015. Senior Vice President - Customer Operations from October 2011 to June 2015.
- Georgia Power — Vice President - Community and Economic Development from 2007 to October 2011. Georgia Power is an affiliate of The Southern Company, a public utility holding company serving the southeastern United States.

Robert M. Garvin. Age 49.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.
- Wisconsin Electric — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.
- ATC — Vice President and General Counsel from 2009 to April 2011.

William J. Guc. Age 46.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- Wisconsin Electric — Vice President and Controller since October 2015.
- Integrys Energy Group — Vice President and Treasurer from December 2010 to June 2015.

J. Patrick Keyes. Age 50.
- WEC Energy Group — Executive Vice President and Chief Financial Officer since September 2012. Treasurer from April 2011 to January 2013. Vice President from April 2011 to August 2012.
- Wisconsin Electric — Director since June 2015. Executive Vice President and Chief Financial Officer since September 2012. Treasurer from April 2011 to January 2013. Vice President from April 2011 to August 2012.
- Accenture — Senior Executive from September 2001 to March 2011.

Scott J. Lauber. Age 50.
- WEC Energy Group — Vice President and Treasurer since February 2013. Assistant Treasurer from March 2011 to January 2013.
- Wisconsin Electric — Vice President and Treasurer since February 2013. Assistant Treasurer from March 2011 to January 2013.

Allen L. Leverett. Age 49.
- WEC Energy Group — President since August 2013. Executive Vice President from May 2004 to July 2013. Chief Financial Officer from July 2003 to February 2011.
-

Wisconsin Electric — Director and President since June 2015. Executive Vice President from May 2004 to June 2015. Chief Financial Officer from July 2003 to February 2011.

Susan H. Martin. Age 63.

- WEC Energy Group — Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.
- Wisconsin Electric — Director since June 2015. Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.

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Charles R. Matthews. Age 59.

- PELLC — President since June 2015.
- PGL — Director, President, and Chief Executive Officer since June 2015.
- NSG — Director, President, and Chief Executive Officer since June 2015.
- Wisconsin Electric — Senior Vice President - Wholesale Energy and Fuels from January 2012 to June 2015. Vice President - Wholesale Energy and Fuels from August 2006 to January 2012.

Joan M. Shafer. Age 62.

- Wisconsin Electric — Executive Vice President - Human Resources and Organizational Effectiveness since June 2015. Senior Vice President - Customer Services from January 2012 to June 2015. Vice President - Customer Services from January 2004 to January 2012.

Mary Beth Straka. Age 51.

- WEC Energy Group — Senior Vice President - Corporate Communications and Investor Relations since June 29, 2015.
- Wisconsin Electric — Senior Vice President - Corporate Communications and Investor Relations from June 1 to June 28, 2015.
- Barclays — Vice President of Equity Research Power and Utilities Group from September 2008 to May 2015.

On January 27, 2016, Mr. Klappa notified WEC Energy Group's Board of Directors (Board) of his decision to retire as Chief Executive Officer (CEO) effective May 1, 2016, after which time he will serve as Non-Executive Chairman of the Board. On the same day, the Board elected Mr. Leverett to the Board and appointed him as CEO effective upon Mr. Klappa's retirement.

Certain executive officers also hold officer and/or director positions at our other significant subsidiaries.

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PART II

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

Number of Common Stockholders

As of January 31, 2016, 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 21, 2016, the Board of Directors increased the quarterly dividend to $0.4950 per share effective with the first quarter of 2016 dividend payment, which equates to an annual dividend of $1.98 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.

Range of WEC Energy Group Common Stock Prices and Dividends

	2015			2014		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$58.01	$47.51	$0.4225	$46.76	$40.17	$0.39
Second	$51.54	$44.93	0.4225	$49.21	$44.03	0.39
Third	$52.29	$44.97	0.4404	$47.02	$41.90	0.39
Fourth	$53.88	$47.98	0.4575	$55.39	$43.01	0.39
Annual	$58.01	$44.93	$1.7429	$55.39	$40.17	$1.56

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ITEM 6. SELECTED FINANCIAL DATA

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

As of or for Year Ended December 31 (in millions, except per share information)	2015 [1]	2014	2013	2012	2011
Operating revenues	$5,926.1	$4,997.1	$4,519.0	$4,246.4	$4,486.4
Net income attributed to common shareholders	638.5	588.3	577.4	546.3	526.2
Total assets [2] [3]	29,355.2	14,905.0	14,443.2	14,163.0	13,823.3
Preferred stock of subsidiary	30.4	30.4	30.4	30.4	30.4
Long-term debt (excluding current portion) [2]	9,124.1	4,170.7	4,347.0	4,437.1	4,597.1
Weighted average common shares outstanding					
Basic	271.1	225.6	227.6	230.2	232.6
Diluted	272.7	227.5	229.7	232.8	235.4
Earnings per share					
Basic	$2.36	$2.61	$2.54	$2.37	$2.26
Diluted	$2.34	$2.59	$2.51	$2.35	$2.24
Dividends per share of common stock	$1.74	$1.56	$1.45	$1.20	$1.04

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

(2) In the fourth quarter of 2015, we early implemented ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. As a result, debt issuance costs previously reported as other long-term assets were reclassified to offset long-term debt for all periods presented. Amounts reclassified were $15.7 million in 2014, $16.2 million in 2013, $16.7 million in 2012, and $17.2 million in 2011.

(3) In the fourth quarter of 2015, we early implemented ASU 2015-17, Balance Sheet Classification of Deferred Taxes. As a result, current deferred income taxes previously reported as a separate component of current assets were reclassified to offset long-term deferred income tax liabilities for all periods presented. Amounts reclassified were $242.7 million in 2014, $310.0 million in 2013, $105.3 million in 2012, and $21.6 million in 2011.

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

CORPORATE DEVELOPMENTS

Introduction

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

Corporate Strategy

Our goal is to create long-term value for our stockholders 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 network.

- The West Central Gas Expansion project went into service in early November 2015. This natural gas lateral will allow Wisconsin Gas to improve the reliability of its natural gas distribution network in the western part of Wisconsin and better meet customer demand.

- PGL is continuing to work on its gas system modernization program (AMRP), 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 System Modernization Reliability Project, 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.

Our investment in reliability related projects has been very successful. In October 2015, We Energies, the trade name of Wisconsin Electric and Wisconsin Gas, was named the most reliable utility in the Midwest by PA Consulting Group for the fifth year in a row. We Energies received the ReliabilityOne™ Award, an annual award that recognizes utilities that excel in delivering reliable electric service.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. We have provided some examples from our generating fleet.

- VAPP is a co-generation plant in Milwaukee that was constructed in 1968. The plant originally utilized coal to produce electricity and steam; however, the plant's fuel source was converted to natural gas with construction completed in November 2015. Changing the fuel source is expected to reduce operating costs and enhance environmental performance without decreasing the plant's capacity.

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Wisconsin Electric received approval from the PSCW to make changes at the Oak Creek Expansion units to enable them to burn coal from the Powder River Basin (PRB) in the Western United States. The coal plant was originally designed to burn coal mined from the Eastern United States, but the price of that coal increased relative to the PRB coal in recent years. This project is expected to create flexibility and enable 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.

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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, Acquisition, for information about the recent acquisition of Integrys.

- 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. In addition to the projects discussed above, other on-going projects are discussed in more detail within Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.

- See Note 3, Dispositions, for more information on the pending sale of ITF.

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.

RESULTS OF OPERATIONS

Consolidated Earnings

The following table compares our consolidated results:

	Year Ended December 31		
(in millions, except per share data)	2015	2014	2013
Wisconsin	$884.2	$770.2	$719.4
Illinois	78.1	—	—
Other states	6.0	—	—
We Power	373.4	368.0	366.6
Corporate and other	(91.2)	(26.1)	(5.9)
Total operating income	1,250.5	1,112.1	1,080.1
Electric transmission	96.1	66.0	68.5
Other income, net	58.9	13.4	18.8
Interest expense	331.4	240.3	250.9
Income before income taxes	1,074.1	951.2	916.5
Income tax expense	433.8	361.7	337.9
Preferred stock dividends of subsidiaries	1.8	1.2	1.2
Net income attributed to common shareholders	$638.5	$588.3	$577.4
Diluted earnings per share	$2.34	$2.59	$2.51

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, partially offset by acquisition costs recorded by us and our subsidiaries. Integrys was acquired on June 29, 2015. See Note 2, Acquisition, for more information. 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.

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2014 Compared with 2013

Earnings increased $10.9 million in 2014, driven by:

- A $50.8 million pre-tax ($30.5 million after tax) increase in operating income at Wisconsin Electric and Wisconsin Gas driven by lower operation and maintenance expense.

- A $10.6 million pre-tax ($6.4 million after tax) decrease in interest expense driven by lower debt levels and lower average interest rates on long-term debt.

These increases in our earnings were partially offset by:

- A $12.5 million decrease in earnings from acquisition costs that were recorded during 2014. See Note 2, Acquisition, for more information on the acquisition.

- An $8.1 million increase in income tax expense due to reduced tax benefits associated with lower Treasury Grant income and decreased AFUDC – Equity.

Wisconsin Segment Contribution to Operating Income

For the periods presented in this Annual Report on Form 10-K, our Wisconsin operations included operations for both Wisconsin Electric and Wisconsin Gas for all periods, and operations for WPS beginning July 1, 2015, due to the acquisition of Integrys and its subsidiaries.

Electric utility margins are defined as electric revenues less fuel and purchased power costs. We believe that electric utility margins provide a more meaningful basis for evaluating electric utility operations than electric revenues since the majority of prudently incurred fuel and purchased power costs are passed through to customers in current rates under enacted fuel rules.

Natural gas utility margins are defined as natural gas revenues less the cost of natural gas sold. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. The average per-unit cost of natural gas sold decreased 34.3% in 2015 and increased 45.8% in 2014, neither of which had an impact on margins.

	Year Ended December 31		
(in millions)	2015	2014	2013
Electric revenues	$4,068.5	$3,445.2	$3,348.3
Fuel and purchased power	1,369.3	1,228.1	1,158.1
Total electric margins	2,699.2	2,217.1	2,190.2
Natural gas revenues	1,122.6	1,496.1	1,113.7
Cost of natural gas sold	640.5	1,036.1	674.1
Total natural gas margins	482.1	460.0	439.6
Other operation and maintenance	1,741.0	1,462.7	1,522.0
Depreciation and amortization	408.6	323.2	272.2
Property and revenue taxes	147.5	121.0	116.2
Operating income	$884.2	$770.2	$719.4

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

	Year Ended December 31		
	MWh (in thousands)		
Electric Sales Volumes	2015	2014	2013
Customer class			
Residential	9,218.9	7,946.3	8,141.9
Small commercial and industrial	10,850.3	8,805.1	8,860.4
Large commercial and industrial	11,126.8	7,393.3	8,673.4
Other	162.6	148.7	152.3
Total retail	31,358.6	24,293.4	25,828.0
Wholesale	2,588.1	1,852.8	1,953.5
Resale	9,077.1	6,497.9	4,382.7
Total sales in MWh	43,023.8	32,644.1	32,164.2
Electric customer choice*	457.9	2,440.0	813.0

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

	Year Ended December 31		
	Therms (in millions)		
Natural Gas Sales Volumes	2015	2014	2013
Customer class			
Residential	859.4	911.5	872.0
Commercial and industrial	527.4	571.7	518.0
Total retail	1,386.8	1,483.2	1,390.0
Transport	1,428.5	1,087.5	1,052.8
Total sales in therms	2,815.3	2,570.7	2,442.8

	Year Ended December 31		
	Degree Days		
Weather	2015	2014	2013
Wisconsin Electric and Wisconsin Gas (1)			
Heating (6,659 normal)	6,468	7,616	7,233
Cooling (712 normal)	622	464	688
WPS (2)			
Heating (2,863 normal)	2,215		
Cooling (364 normal)	396		

(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 have been included beginning July 1, 2015.

2015 Compared with 2014

Operating Income

Operating income at the Wisconsin segment increased $114.0 million, driven by a $122.8 million increase due to the inclusion of WPS operating income beginning July 1, 2015, as a result of the acquisition of Integrys on June 29, 2015. Without the inclusion of WPS operating income, operating income at the Wisconsin segment decreased $8.8 million in 2015.

Significant factors impacting the $8.8 million decrease in operating income were:

- An aggregate $35.8 million decrease in natural gas margins at Wisconsin Electric and Wisconsin Gas in 2015. This decrease was primarily driven by a $42.7 million decrease from sales volume variances 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 Wisconsin Electric and Wisconsin Gas PSCW rate orders, effective January 1, 2015. See Note 22, Regulatory Environment, for more information.

- An aggregate $25.5 million increase in other operation and maintenance expense at Wisconsin Electric and Wisconsin Gas in 2015. This increase was driven by:

A $48.6 million increase from higher PTF lease expense and associated operating and maintenance expenses as approved in Wisconsin Electric's PSCW rate order, effective January 1, 2015.

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

These increases in other operation and maintenance expenses were partially offset by:

A $16.1 million decrease in employee benefits 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.

Other decreases in other operation and maintenance expenses that were not individually significant.

- A $24.5 million increase in other depreciation and amortization expense at Wisconsin Electric and Wisconsin Gas, driven by:

An overall increase in utility plant in service in 2015. During 2015, Wisconsin Gas completed the Western Gas lateral project, and Wisconsin Electric 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 a Treasury Grant associated with the completion of our biomass plant in 2013. The lower grant income corresponds to lower bill credits provided to our retail electric customers in Wisconsin.

- A combined $6.0 million increase in property and revenue taxes at Wisconsin Electric and Wisconsin Gas in 2015.

These decreases in operating income were significantly offset by an $83.0 million increase in electric margins at Wisconsin Electric 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. See Note 23, Michigan Settlement, for more information. A large portion of this increase in margins was offset by higher transmission expense included in other operation and maintenance expense at Wisconsin Electric.

- A $10.4 million increase in positive collections of fuel and purchased power costs compared with costs approved in rates in 2015, as compared with 2014. Under the fuel rule, Wisconsin Electric defers under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates, and the remaining variance impacts margins.

- A $6.2 million increase primarily due to lower fly ash removal costs in 2015. These costs are not included in the fuel rule recovery mechanism.

- A partially offsetting $22.3 million decrease in electric margins 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. Certain wholesale customers have provisions in their contracts which allow them to reduce the amount of energy we provide to them.

2014 Compared with 2013

Operating Income

Operating income at the Wisconsin segment increased $50.8 million in 2014, driven by:

- A $120.9 million increase in sales for resale in 2014 due to higher sales into the MISO Energy Markets as a result of Michigan's alternative electric supplier program and increased availability of our generating units. The margins on these sales are used to reduce fuel costs for our retail customers.

- A $59.4 million increase in other operating revenues in 2014, primarily driven by the recognition of $56.4 million related to revenues under the SSR agreement with MISO. See Note 23, Michigan Settlement, for more information.

- A $59.3 million decrease in other operation and maintenance expense in 2014. This decrease was primarily driven by lower benefit costs related to pensions, postretirement, and medical costs. Our operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages, and amortization of regulatory assets.

- A $38.3 million increase in Wisconsin net retail pricing in 2014, primarily related to Wisconsin Electric's PSCW rate order, effective January 1, 2013.

- A $15.8 million increase in natural gas margins, primarily due to colder winter weather in 2014. We estimate that colder winter weather increased natural gas margins by approximately $11.2 million. As measured by heating degree days, 2014 was 5.3% colder than 2013 and 15.4% colder than normal.

These increases in operating income were partially offset by:

- A $78.4 million decrease in large commercial and industrial sales in 2014 due to the two iron ore mines switching to an alternative electric supplier in September 2013.

- A $69.5 million increase in electric fuel and purchased power costs in 2014. This increase was primarily driven by a 1.5% increase in total MWh sales and higher generating costs due to an increase in natural gas prices.

- A $51.0 million increase in depreciation and amortization expense in 2014. The increase was partially driven by lower income received from a Treasury Grant in 2014. During 2014, we recognized $17.4 million of income related to a Treasury Grant associated with the completion of the biomass plant, compared to $48.0 million in 2013. The lower grant income corresponds to the lower bill credits provided to Wisconsin Electric's retail electric customers in Wisconsin in 2014. In addition, an overall increase in utility plant in service as a result of the biomass plant that went into service in November 2013 contributed to the increase in depreciation and amortization expense.

- A $45.8 million decrease in electric revenues related to unseasonably cool summer weather in 2014. As measured by cooling degree days, 2014 was 36.6% cooler than normal and 32.6% cooler than 2013 due to mild second and third quarters. The unfavorable impact of the cool summer weather was partially offset by the cold winter weather.

Residential sales decreased 2.4%, primarily due to the weather.

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Sales to our large commercial and industrial customers decreased 14.8% primarily due to the loss of the two iron ore mines in Michigan. If the mines were excluded, sales to our large commercial and industrial customers would have decreased 1.1%.

Illinois Segment Contribution to Operating Income	
(in millions)	2015
Natural gas revenues	$503.4
Cost of natural gas sold	133.2
Total natural gas margins	370.2
Other operation and maintenance	219.6
Depreciation and amortization	63.3
Property and revenue taxes	9.2
Operating income	$78.1

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

	Therms (in millions)
Natural Gas Sales Volumes	2015
Customer Class	
Residential	300.7
Commercial and industrial	63.2
Total retail	363.9
Transport	328.4
Total sales in therms	692.3

	Degree Days
Weather *	2015
Heating (2,282 normal)	1,813

* Normal heating degree days are based on a 12-year moving average of monthly total heating degree days at 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.

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. The following table shows the impact of these riders on margins and operating expenses.

(in millions)	2015
Environmental cleanup costs	$9.2
Energy efficiency program	7.4
Bad debt rider	3.6
Total increase in margins and operating expenses	$20.2

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Other States Segment Contribution to Operating Income

(in millions)	2015
Natural gas revenues	$149.3
Cost of natural gas sold	76.9
Total natural gas margins	72.4
Other operation and maintenance	50.0
Depreciation and amortization	10.0
Property and revenue taxes	6.4
Operating income	$6.0

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

	Therms (in millions)
Natural Gas Sales Volumes	2015
Customer Class	
Residential	84.7
Commercial and industrial	60.9
Total retail	145.6
Transport	279.6
Total sales in therms	425.2

	Degree Days
Weather *	2015
Heating (2,744 normal)	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, gross margin is sensitive to weather and is generally higher during the winter months.

We Power Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	2015	2014	2013
Operating income	$373.4	$368.0	$366.6

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 Wisconsin Electric.

2014 Compared with 2013

Operating income at the We Power segment increased $1.4 million, or 0.4%, when compared to 2013.

Corporate and Other Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	2015	2014	2013
Operating loss	$(91.2)	$(26.1)	$(5.9)

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2015 Compared with 2014

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. See Note 2, Acquisition, for more information regarding costs associated with the acquisition.

2014 Compared with 2013

Operating loss at the corporate and other segment increased $20.2 million when compared to 2013. This was primarily attributable to external costs incurred in 2014 related to the acquisition of Integrys.

Electric Transmission Segment Operations

	Year Ended December 31		
(in millions)	2015	2014	2013
Earnings from ATC	$96.1	$66.0	$68.5

2015 Compared with 2014

Earnings from our ownership interest in ATC increased $30.1 million when compared to 2014, 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. 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. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – ATC Allowed ROE Complaint, for more information.

2014 Compared with 2013

Earnings from our ownership interest in ATC decreased $2.5 million when compared to 2013. ATC reduced its earnings in 2014, driven by a potential refund to customers related to a complaint filed with the FERC requesting lower ROE for certain transmission owners.

Consolidated Other Income, Net

	Year Ended December 31		
(in millions)	2015	2014	2013
AFUDC – Equity	$20.1	$5.6	$18.3
Gain on asset sales	22.9	7.5	0.8
Other, net	15.9	0.3	(0.3)
Other income, net	$58.9	$13.4	$18.8

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 after the acquisition on June 29, 2015.

2014 Compared with 2013

Other income, net decreased by $5.4 million, when compared to 2013. This decrease primarily relates to lower AFUDC – Equity related to the biomass plant going into service in November 2013, which was partially offset by an increased gain on asset sales.

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Consolidated Interest Expense

	Year Ended December 31		
(in millions)	2015	2014	2013
Interest expense	$331.4	$240.3	$250.9

2015 Compared with 2014

Interest expense increased by $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.

2014 Compared with 2013

Interest expense decreased by $10.6 million, or 4.2%, when compared to 2013, primarily because of lower debt levels and lower average interest rates on long-term debt.

Consolidated Income Tax Expense

	Year Ended December 31		
	2015	2014	2013
Effective tax rate	40.4 %	38.0 %	36.9 %

2015 Compared with 2014

Our effective tax rate was 40.4% in 2015 compared to 38.0% in 2014. This increase was primarily due to an increase in non-deductible acquisition related expenses. See Note 15, Income Taxes, for more information. We expect our 2016 annual effective tax rate to be between 37.5% and 38.5%.

2014 Compared with 2013

Our effective tax rate applicable to continuing operations was 38.0% in 2014 compared to 36.9% in 2013. This increase in our effective tax rate was due to reduced tax benefits associated with Treasury Grant income, decreased AFUDC – Equity, and non-deductible acquisition related expenses.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following summarizes our cash flows during 2015, 2014, and 2013:

(in millions)	2015	2014	2013	Change in 2015 Over 2014	Change in 2014 Over 2013
Cash provided by (used in):					
Operating activities	$1,293.6	$1,198.9	$1,232.2	$94.7	$(33.3)
Investing activities	(2,517.5)	(756.8)	(745.8)	(1,760.7)	(11.0)
Financing activities	1,211.8	(406.2)	(496.0)	1,618.0	89.8

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Operating Activities

2015 Compared with 2014

Net cash provided by operating activities increased $94.7 million in 2015, driven by a $141.6 million increase related to net cash flows from the operating activities of Integrys in the last six months of 2015 as a result of the acquisition on June 29, 2015. See Note 2, Acquisition, for more information.

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

- A $141.4 million decrease in cash related to higher payments for operating and maintenance costs in 2015.

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

These decreases in cash provided by operating activities from legacy Wisconsin Energy Corporation companies were partially offset by a $174.4 million net increase in cash related to lower payments for natural gas, fuel, and purchased power, partially offset by a decrease in cash driven by lower overall collections from customers in 2015. This net increase was primarily due to the impact of lower commodity prices in 2015.

2014 Compared with 2013

Net cash provided by operating activities decreased $33.3 million in 2014. During 2014, we experienced higher net income, higher depreciation expense and favorable cash flows from accounts receivable, primarily because of the timing of the Treasury Grant. More than offsetting these favorable items were increases in working capital related to natural gas in storage and increases in regulatory assets.

Investing Activities

2015 Compared with 2014

Net cash used in investing activities increased $1,760.7 million in 2015, driven by:

- An investment of $1,329.9 million related to the June 29, 2015, acquisition of Integrys, which is net of cash acquired of $156.3 million. See Note 2, Acquisition, for more information.

- A $505.0 million increase in cash used for capital expenditures in 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.

2014 Compared with 2013

Net cash used in investing activities increased $11.0 million in 2014, driven by higher capital expenditures of $36.0 million, which is discussed in more detail below. This increase in cash used in investing activities was partially offset by an increase in proceeds received from asset sales.

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Capital Expenditures

The following table summarizes our capital expenditures by business segment by year:

Reportable Segment (in millions)	2015	2014	2013	Change in 2015 over 2014	Change in 2014 over 2013
Wisconsin	$950.3	$715.0	$695.7	$235.3	$19.3
Illinois	194.4	—	—	194.4	—
Other states	34.7	—	—	34.7	—
We Power	53.4	41.0	25.8	12.4	15.2
Corporate and other	33.4	5.2	3.7	28.2	1.5
Total	$1,266.2	$761.2	$725.2	$505.0	$36.0

2015 Compared with 2014

The increase in capital expenditures in the Wisconsin segment in 2015 was primarily due to the inclusion of WPS as a result of the acquisition of Integrys on June 29, 2015. Significant projects included in 2015 capital expenditures for WPS include the ReACT™ emission control technology project at Weston Unit 3 and the System Modernization and Reliability Project, which is a project to underground and upgrade certain electric distribution facilities in northern Wisconsin. The Wisconsin segment also included increased expenditures in 2015 related to Wisconsin Gas's Western Gas Lateral project, which was a project to improve the reliability of Wisconsin Gas's natural gas distribution network in the western part of Wisconsin and to better meet customer demand. These increases were partially offset by lower capital expenditures in 2015 for Wisconsin Electric'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. For additional discussion regarding ReACT™, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements – Capital Expenditures and Significant Capital Projects.

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

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

2014 Compared with 2013

The increase in capital expenditures in the Wisconsin segment in 2014 was primarily driven by the starting of the conversion of the fuel source for VAPP from coal to natural gas.

See Capital Expenditures and Significant Capital Projects below for more information.

Financing Activities

2015 Compared with 2014

Net cash from financing activities increased $1,618.0 million in 2015, driven by:

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

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

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

- A $205.3 million increase in retirements of long-term debt in 2015, of which $130.1 million was attributable 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 associated with the Integrys acquisition and an increase in our quarterly dividend rate effective with the closing of the acquisition on June 29, 2015. See Note 2, Acquisition and Note 11, Common Equity, for more information.

- A $52.7 million decrease in cash due to the redemption of all of WPS's preferred stock in 2015. See Note 12, Preferred Stock, for more information.

2014 Compared with 2013

Net cash used in financing activities decreased $89.8 million in 2014, primarily driven by a decrease in common stock repurchased as a result of our Board of Directors terminating our share repurchase program in connection with the acquisition of Integrys. During 2014, we repurchased $18.6 million of common stock as compared to $126.0 million in 2013 as part of the share repurchase program. See Note 11, Common Equity, for more information on share repurchases. Our dividends paid on common stock increased $23.1 million in 2014 as a result of increases in the quarterly common stock dividend of 12.5% and 2.0% in the third quarter of 2013 and first quarter of 2014, respectively.

Significant Financing Activities

For information on our short-term debt, see Note 13, Short-Term Debt and Lines of Credit.

For information on our long-term debt, see 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, Wisconsin Electric, Wisconsin Gas, 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 and other short-term credit agreements.

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The following table shows our capitalization structure as of December 31, 2015 and 2014, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view our 2007 6.25% Series A Junior Subordinated Notes due 2067 (6.25% Junior Notes), Integrys's 2006 6.11% Junior Subordinated Notes due 2066 (6.11% Junior Notes), and Integrys's 2013 6.00% Junior Subordinated Notes due 2073 (6.00% Junior Notes) (collectively, Junior Notes):

	2015		2014	
(in millions)	Actual	Adjusted	Actual	Adjusted
Common equity	$8,654.8	$9,239.7	$4,419.7	$4,669.7
Preferred stock of subsidiary	30.4	30.4	30.4	30.4
Long-term debt (including current maturities)	9,281.8	8,696.9	4,594.8	4,344.8
Short-term debt	1,095.0	1,095.0	617.6	617.6
Total capitalization	$19,062.0	$19,062.0	$9,662.5	$9,662.5
Total debt	$10,376.8	$9,791.9	$5,212.4	$4,962.4
Ratio of debt to total capitalization	54.4 %	51.4 %	53.9 %	51.4 %

Included in long-term debt on our balance sheets as of December 31, 2015 and 2014, is $1,169.8 million and $500.0 million aggregate principal amount of Junior Notes and 6.25% Junior Notes, respectively. The adjusted presentation attributes $584.9 million of the Junior Notes to common equity and $584.9 million to long-term debt in 2015 and $250.0 million of the 6.25% Junior Notes to common equity and $250.0 million to long-term debt in 2014. We believe this presentation is consistent with the 50% equity credit the majority of rating agencies currently attribute to the Junior Notes.

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 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.

In February 2016, Integrys repurchased and retired approximately $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.

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, 2015, 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, 2015, our current liabilities exceeded our current assets by $502.2 million. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place for ongoing operations. We also have access to the capital markets to finance our construction programs and to refinance current maturities of long-term debt if necessary.

Capital Requirements

Acquisition of Integrys

The acquisition of Integrys on June 29, 2015, was financed through the issuance of approximately 90.2 million shares of Wisconsin Energy Corporation common stock, $1.2 billion of long-term debt, and $300.0 million of commercial paper. See Note 2, Acquisition, for more information on the acquisition.

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2015:

	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]	$18,155.9	$539.3	$1,763.0	$1,748.9	$14,104.7
Capital lease obligations [3]	130.5	45.1	28.6	31.9	24.9
Operating lease obligations [4]	107.1	9.8	18.8	11.9	66.6
Energy and transportation purchase obligations [5]	12,677.7	1,164.7	1,739.7	1,330.6	8,442.7
Purchase orders [6]	824.8	629.1	138.5	41.3	15.9
Pension and OPEB funding obligations [7]	68.6	30.4	38.2	—	—
Capital contributions to equity method investments	9.0	9.0	—	—	—
Total contractual obligations	$31,973.6	$2,427.4	$3,726.8	$3,164.6	$22,654.8

(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 Wisconsin Electric 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 2018.

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 $571.2 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)	2016	2017	2018
Wisconsin (1)	$934.6	$998.0	$1,055.2
Illinois (2)	375.5	390.9	387.0
Other states	60.1	64.6	64.0
We Power	49.3	60.5	38.5
Corporate and other	90.9	48.5	5.3
Total	$1,510.4	$1,562.5	$1,550.0

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(1) WPS is in the process of constructing a multi-pollutant control technology known as ReACT™ as part of Weston Unit 3. The control technology will help meet the requirements of a Consent Decree agreed to between WPS and the EPA. The technology will also assist with WPS's compliance with future air pollution regulations, as well as help maintain a balanced generation portfolio. The cost of the project is estimated at approximately $342.0 million, excluding AFUDC, with a targeted completion date of April 2016.

(2) PGL is continuing work on the AMRP, a 20-year project that began in 2011 under which PGL is replacing approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved qualifying infrastructure plant rider, which is in effect through 2023. PGL expects to invest between $250 million and $280 million annually over the next three years.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $317 million from 2016 through 2018.

Common Stock Matters

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

On January 21, 2016, the Board of Directors increased the quarterly dividend to $0.4950 per share effective with the first quarter of 2016 dividend payment, which equates to an annual dividend of $1.98 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, 2015. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $121 million, $13.9 million, and $22.8 million to our pension and OPEB plans in 2015, 2014, and 2013, respectively. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note 17, Employee Benefits.

Off-Balance Sheet Arrangements

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which 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 effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources that is material to our investors. For additional information regarding guarantees and other off-balance sheet arrangements, see 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 environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery

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

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these 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 costs is not approved by our regulators, the costs are 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, 2015, our regulatory assets totaled $3,101.7 million and our regulatory liabilities totaled $1,426.0 million.

Regarding our ReACT™ project, the PSCW approved deferral of costs above the originally authorized $275.0 million level through 2016. We will be required to obtain a separate approval for collection of these deferred costs. Also, prior to the acquisition, Integrys initiated an IT project with the goal of improving the customer experience. Specifically, the project is expected to provide functional and technological benefits to the billing, call center, and credit collection functions. As of December 31, 2015, none of the costs have been disallowed in rate proceedings. We will be required to obtain approval for the recovery of additional costs incurred through the completion of this long-term project See Note 22, Regulatory Environment, for additional information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Commodity Costs

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

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

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 1(d), Revenues and Customer Receivables, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric revenues 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 revenues are unfavorably sensitive to above normal temperatures during the winter heating season. Certain of our natural gas utilities 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 2015, 2014, and 2013, 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 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, 2015, and December 31, 2014, a hypothetical increase in market interest rates of one-percentage point would have increased annual interest expense by $11.0 million and $6.2 million, 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.

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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, 2015	Expected Return on Assets in 2016
Pension trust funds	$2,755.1	7.13 %
OPEB trust funds	$749.8	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 and Risk Factors in Item 1A.

Industry Restructuring

Electric Utility Industry

The regulated energy industry continues to experience significant changes. 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 retail choice.

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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. The law limits customer choice to 10% of our Michigan retail load, but the two iron ore mines in our service territory are excluded from this cap. See Note 23, Michigan Settlement, for information on the mines' ability to switch to an alternative electric supplier. 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

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 deregulate the sale of natural gas in customer classes with workably competitive market choices and has 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 a third party supplier. However, work on deregulation of the natural gas distribution industry by the PSCW continues to be on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

Restructuring in Illinois

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

PGL and NSG offer natural gas transportation service to customers that select an alternative retail natural gas supplier. Transportation customers purchase natural gas directly from an alternative retail natural gas supplier and use PGL's and NSG's distribution systems to transport the natural gas to their facilities. PGL and NSG still earn a distribution charge when they transport natural gas for these customers. 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 Minnesota

We are unaware of any current efforts to deregulate the sale of natural gas in Minnesota. While potential future efforts to deregulate the sale of natural gas could occur, we are unable to predict the impact of any potential future deregulation on our results of operations or financial position.

Restructuring in Michigan

The option to choose an alternative retail natural gas supplier has been provided to WPS's and MGU's customers since the late 1990s and 2005, respectively. WPS and MGU are not required by the MPSC or state law to make this option available to customers, but since this option is currently provided to customers, WPS and MGU would need MPSC approval to eliminate it.

WPS and MGU offer natural gas transportation service to customers that select an alternative retail natural gas supplier. Transportation customers purchase natural gas directly from an alternative retail natural gas supplier and use WPS's and MGU's distribution systems to transport the natural gas to their facilities. WPS and MGU still earn a distribution charge when they transport natural gas for these customers. 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.

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Environmental Matters

Cross-State Air Pollution Rule

In July 2011, the EPA issued the CSAPR, which replaced a previous rule, the Clean Air Interstate Rule (CAIR). The purpose of the CSAPR was to limit the interstate transport of emissions of NOx and SO_2 that contribute to fine particulate matter and ozone nonattainment in downwind states through a proposed allocation plan and allowance trading scheme. The rule was to become effective in January 2012. However, in December 2011, the CSAPR requirements were stayed by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals) and CAIR was implemented during the stay period. In August 2012, the D.C. Circuit Court of Appeals issued a ruling vacating and remanding CSAPR and simultaneously reinstating CAIR pending the issuance of a replacement rule by the EPA. The case was appealed to the United States Supreme Court (Supreme Court). In April 2014, the Supreme Court issued a decision largely upholding CSAPR and remanded it to the D.C. Circuit Court of Appeals for further proceedings. 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 compliance deadlines were also changed by three years, so that Phase I emissions budgets apply in 2015 and 2016, and Phase 2 emissions budgets will apply to 2017 and beyond.

In December 2015, the EPA published its proposed update to the CSAPR for the 2008 ozone NAAQS and plans to issue a final rule by August 2016. Starting in 2017, this proposed rule would reduce ozone season (May 1 through September 30) NOx emissions from power plants in 23 states in the eastern United States. In this rule, the EPA is proposing to update Phase II CSAPR NOx ozone season budgets for electric generating units in the 23 states. An approximate 60% reduction in NOx emissions is proposed for Wisconsin and an approximate 29% reduction is proposed for Michigan, beginning in May 2017. Additional investments in controls and/or shifts in generation may be required depending upon the final outcome of the rule. We submitted comments to the EPA on the potential impacts of the rule.

See Note 18, Commitments and Contingencies, for a discussion of additional environmental matters affecting us, including rules and regulations relating to air quality, water quality, land quality, renewable energy requirements, and climate change.

Other Matters

American Transmission Company Allowed Return On Equity Complaint

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting to reduce the base ROE used by MISO transmission owners, including ATC, to 9.15%. ATC's current authorized ROE is 12.2%. In October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 12, 2013. The FERC conducted hearings in August 2015, and the ALJ issued an initial decision in December 2015. The ALJ's initial decision recommended 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 ALJ's recommendation is not binding to the FERC. A FERC order related to this complaint is expected during the fourth quarter of 2016.

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 the filing date of the complaint. The FERC conducted hearings in February 2016 with respect to this second complaint, and an initial decision is expected by June 30, 2016.

In October 2014, the FERC issued an order, in regard to a similar complaint, reducing the base ROE for New England transmission owners from their existing rate of 11.14% to 10.57%. In this order, the FERC used a revised method for determining the appropriate ROE for FERC-jurisdictional electric utilities. The FERC expects its new methodology will narrow the "zone" of reasonable returns on equity. The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues to be guided by the New England transmission decision.

Any change to ATC's ROE could result in lower equity earnings and distributions from ATC in the future. We are currently unable to determine how the FERC may rule in these complaints. However, we believe it is probable that refunds will be required upon resolution of these issues. Based on the ALJ's initial decision in December 2015, ATC reduced its earnings, which resulted in us recognizing lower earnings from our investment in ATC.

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Wisconsin Power and Light's (WP&L) Riverside Energy Center Facility

In April 2015, WP&L filed a CPCN application with the PSCW for approval to construct an approximate 650 MW natural gas-fired combined-cycle generating unit in Beloit, Wisconsin. Recent construction proposals received by WP&L indicate that the unit could generate up to 700 MWs. In the third quarter of 2015, Wisconsin Electric and WPS requested and received intervention in this proceeding. As intervenors, Wisconsin Electric and WPS proposed purchased power agreement alternatives to the new generating unit. In December 2015, Wisconsin Electric, WPS, and WP&L entered into a settlement agreement that was approved by the PSCW. Based on the settlement agreement, the generating unit cannot become commercially operational before June 1, 2020. In addition, WP&L must enter into a purchased power agreement with Wisconsin Electric for MISO planning years 2017, 2018, and 2019, whereby Wisconsin Electric will sell and WP&L will purchase capacity and energy at certain agreed upon prices. WPS also will have the option to purchase an undivided ownership interest of up to 100 MWs of generating capacity from the unit during the first two years of operation and up to an aggregate 200 MWs of generating capacity during the third and fourth years of operation. Other major terms of the settlement included agreement on ownership of future Wisconsin Electric and WPS natural gas units, negotiation of a renewable generation joint development plan, and ownership terms of the jointly-owned Columbia plant.

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 deductible depreciation that is awarded above and beyond what would normally be available. Due to the resulting increase in federal tax depreciation, we did not make federal income tax payments for 2015, 2014, or 2013.

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

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. Goodwill is assessed for impairment at least annually or more frequently if a triggering event occurs. If the carrying amount of a reporting unit is greater than its fair value, impairment may be present. When evaluating goodwill for impairment, a qualitative assessment, referred to as the step zero approach, may first be performed to determine whether further quantitative analysis is necessary. If the qualitative assessment indicates that a reporting unit's fair value more likely than not exceeds its carrying value, the two-step quantitative analysis is unnecessary. However, the quantitative analysis needs to be performed if the qualitative assessment indicates that a reporting unit's carrying value more likely than not exceeds its fair value. The quantitative analysis involves calculating the estimated fair value of the reporting unit. Since the qualitative assessment is optional, companies are allowed to proceed directly to the quantitative analysis.

We completed our annual goodwill impairment test for all of our reporting units that carried a goodwill balance effective August 31, 2015. Our reporting units are the same as our reportable segments. We performed the step zero qualitative analysis since all of our reporting units were either valued recently in connection with the acquisition of Integrys or passed their most recent goodwill impairment test by a significant amount. In addition, no events occurred that would have more likely than not caused a significant decrease in the fair values of our reporting units. Events and circumstances we considered when performing the step zero analysis included, but were not limited to, macro-economic conditions, market and industry conditions, internal cost factors, share price fluctuations, competitive environment, and the operational stability and overall financial performance of the reporting units. After evaluating and weighing all relevant events and circumstances, we concluded that the carrying amounts of our reporting units were

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significantly exceeded by their respective fair values. Consequently, no reporting units were at risk of impairment. No impairment charges were recorded in 2015 as a result of our qualitative annual impairment assessment.

Our reporting units had the following goodwill balances at December 31, 2015:

(in millions, except percentages)	Goodwill	Percentage of Total Goodwill
Wisconsin	$2,109.5	69.8 %
Illinois	731.2	24.2 %
Other states	182.8	6.0 %
Total goodwill	$3,023.5	100.0 %

See Note 10, Goodwill and Other Intangible Assets, 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 2015 Pension Cost
Discount rate	(0.5)	$198.0	$10.6
Discount rate	0.5	(172.1)	(9.9)
Rate of return on plan assets	(0.5)	N/A	10.8
Rate of return on plan assets	0.5	N/A	(10.8)

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 2015 Postretirement Benefit Cost
Discount rate	(0.5)	$53.5	$2.1
Discount rate	0.5	(47.3)	(1.7)

Health care cost trend rate	(0.5)	(33.9)	(3.5)
Health care cost trend rate	0.5	38.5	4.0
Rate of return on plan assets	(0.5)	N/A	2.7
Rate of return on plan assets	0.5	N/A	(2.7)

In the fourth quarter of 2014, the Society of Actuaries published a new set of mortality tables, which updated life expectancy assumptions. We have adjusted the tables to better reflect our plan-specific mortality experience and other general assumptions. We have incorporated the revised mortality tables into the projected pension and OPEB obligations at December 31, 2015.

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The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds with maturities between 0 and 30 years. 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 7.37% in 2015, and 7.25% in both 2014 and 2013, respectively. The actual rate of return on pension plan assets, net of fees, was (3.85)%, 6.17%, and 10.92%, in 2015, 2014, and 2013, 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 at the electric and natural gas utilities, 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 meet 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, 2015, we had $3,101.7 million in regulatory assets and $1,426.0 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 2015 of approximately $5.8 billion included accrued utility revenues of $418.3 million as of December 31, 2015.

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.

ITEM 7A. 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 in Item 7. of this report, as well as Note 1(t), Derivative Instruments, Note 1(s), Fair Value Measurements, and Note 16, Guarantees, for information concerning potential market risks to which we are exposed.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2015 and 2014, 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, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedules 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. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

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, 2015, 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 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2016

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A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2015, 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, 2015, 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 and financial statement schedules as of and for the year ended December 31, 2015 of the Company and our report dated February 26, 2016 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2016

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B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 (in millions, except per share amounts)	2015	2014	2013
Operating revenues	$5,926.1	$4,997.1	$4,519.0
Operating expenses			
Cost of sales	2,240.1	2,259.4	1,827.1
Other operation and maintenance	1,709.3	1,112.4	1,155.0
Depreciation and amortization	561.8	391.4	340.1
Property and revenue taxes	164.4	121.8	116.7
Total operating expenses	4,675.6	3,885.0	3,438.9
Operating income	1,250.5	1,112.1	1,080.1
Equity in earnings of transmission affiliate	96.1	66.0	68.5
Other income, net	58.9	13.4	18.8
Interest expense	331.4	240.3	250.9
Other expense	(176.4)	(160.9)	(163.6)
Income before income taxes	1,074.1	951.2	916.5
Income tax expense	433.8	361.7	337.9
Net income	640.3	589.5	578.6
Preferred stock dividends of subsidiaries	1.8	1.2	1.2
Net income attributed to common shareholders	$638.5	$588.3	$577.4
Earnings per share			
Basic	$2.36	$2.61	$2.54
Diluted	$2.34	$2.59	$2.51
Weighted average common shares outstanding			
Basic	271.1	225.6	227.6
Diluted	272.7	227.5	229.7

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

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C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (in millions)	2015	2014	2013
Net income	$640.3	$589.5	$578.6
Other comprehensive 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	(0.8)	—	—
Cash flow hedges, net	10.6	—	—
Defined benefit plans			
Pension and OPEB costs arising during period, net of tax of $4.2	(6.3)	—	—
Other comprehensive income, net of tax	4.3	—	—
Comprehensive income	644.6	589.5	578.6
Preferred stock dividends of subsidiaries	1.8	1.2	1.2
Comprehensive income attributed to common shareholders	$642.8	$588.3	$577.4

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

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D. CONSOLIDATED BALANCE SHEETS

At December 31

(in millions, except share and per share amounts)	2015	2014
Assets		
Property, plant, and equipment		
In service	$26,249.5	$15,509.0
Accumulated depreciation	(7,919.1)	(4,485.1)
	18,330.4	11,023.9
Construction work in progress	822.9	191.8
Leased facilities, net	36.4	42.0
Net property, plant, and equipment	19,189.7	11,257.7
Investments		
Equity investment in transmission affiliate	1,380.9	424.1
Other	85.8	32.8
Total investments	1,466.7	456.9
Current assets		
Cash and cash equivalents	49.8	61.9
Accounts receivable and unbilled revenues, net of reserves of $113.3 and $74.5, respectively	1,028.6	643.4
Materials, supplies, and inventories	687.0	400.6
Assets held for sale	96.8	—
Prepayments	285.8	148.2
Other	58.8	38.6
Total current assets	2,206.8	1,292.7
Deferred charges and other assets		
Regulatory assets	3,064.6	1,271.2
Goodwill	3,023.5	441.9
Other	403.9	184.6
Total deferred charges and other assets	6,492.0	1,897.7
Total assets	$29,355.2	$14,905.0
Capitalization and liabilities		
Capitalization		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,683,496 and 225,517,339 shares outstanding, respectively	$3.2	$2.3
Additional paid in capital	4,347.2	300.1
Retained earnings	4,299.8	4,117.0
Accumulated other comprehensive income	4.6	0.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	9,124.1	4,170.7
Total capitalization	17,809.3	8,620.8
Current liabilities		
Current portion of long-term debt	157.7	424.1
Short-term debt	1,095.0	617.6
Accounts payable	815.4	363.3
Accrued payroll and benefits	169.7	95.1
Other	471.2	168.6
Total current liabilities	2,709.0	1,668.7
Deferred credits and other liabilities		

Regulatory liabilities	1,392.2	830.6
Deferred income taxes	4,622.3	2,664.0
Deferred revenue, net	579.4	614.1
Pension and other postretirement benefit obligations	543.1	203.8
Environmental remediation	628.2	32.6
Other	1,071.7	270.4
Total deferred credits and other liabilities	8,836.9	4,615.5
Commitments and contingencies (Note 18)		
Total capitalization and liabilities	$29,355.2	$14,905.0

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

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E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (in millions)	2015	2014	2013
Operating activities			
Net income	$640.3	$589.5	$578.6
Reconciliation to cash provided by operating activities			
Depreciation and amortization	583.5	417.0	396.0
Deferred income taxes and investment tax credits, net	418.7	328.1	312.7
Contributions to pension and OPEB plans	(121.0)	(13.9)	(22.8)
Change in –			
Accounts receivable and unbilled revenues	84.0	80.7	(162.9)
Materials, supplies, and inventories	(69.4)	(71.2)	31.3
Other current assets	(27.2)	(13.9)	2.8
Accounts payable	(9.3)	23.7	(14.8)
Accrued taxes, net	35.7	(11.4)	36.6
Other current liabilities	(21.6)	(33.9)	(1.5)
Other, net	(220.1)	(95.8)	76.2
Net cash provided by operating activities	1,293.6	1,198.9	1,232.2
Investing activities			
Capital expenditures	(1,266.2)	(761.2)	(725.2)
Business acquisition, net of cash acquired of $156.3	(1,329.9)	—	—
Investment in transmission affiliate	(8.7)	(13.1)	(10.5)
Proceeds from asset sales	28.9	13.9	2.5
Proceeds from cashout of corporate owned life insurance policies	17.3	—	—
Other, net	41.1	3.6	(12.6)
Net cash used in investing activities	(2,517.5)	(756.8)	(745.8)
Financing activities			
Exercise of stock options	30.1	50.3	48.5
Purchase of common stock	(74.7)	(123.2)	(223.4)
Dividends paid on common stock	(455.4)	(352.0)	(328.9)
Redemption of WPS preferred stock	(52.7)	—	—
Issuance of long-term debt	2,150.0	250.0	251.0
Retirement of long-term debt	(529.6)	(324.3)	(397.2)
Change in short-term debt	163.0	80.2	142.8
Other, net	(18.9)	12.8	11.2
Net cash provided by (used in) financing activities	1,211.8	(406.2)	(496.0)
Net change in cash and cash equivalents	(12.1)	35.9	(9.6)
Cash and cash equivalents at beginning of year	61.9	26.0	35.6
Cash and cash equivalents at end of year	$49.8	$61.9	$26.0

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

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F. CONSOLIDATED STATEMENTS OF EQUITY

(in millions, expect per share amounts)	WEC Energy Group Common Shareholders' Equity Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Common Shareholders' Equity	Preferred Stock of Subsidiaries	Total Equity
Balance at December 31, 2012	$2.3	$500.3	$3,632.2	$0.3	$4,135.1	$ 30.4	$4,165.5
Net income attributed to common shareholders	—	—	577.4	—	577.4	—	577.4
Common stock dividends of $1.45 per share	—	—	(328.9)	—	(328.9)	—	(328.9)
Exercise of stock options	—	48.5	—	—	48.5	—	48.5
Purchase of common stock	—	(223.4)	—	—	(223.4)	—	(223.4)
Stock-based compensation and other	—	24.3	—	—	24.3	—	24.3
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

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

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G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 (in millions)				2015	2014
Common equity (see accompanying statement)				$8,654.8	$4,419.7
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	—
	2.45%		2020	400.0	—
	3.55%		2025	500.0	—
	6.20%		2033	200.0	200.0
WEC Energy Group Junior Notes (unsecured)	6.25%		2067	500.0	500.0
Wisconsin Electric Debentures (unsecured)	6.25%		2015	—	250.0
	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	—
	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	—
	6.875%		2095	100.0	100.0
WPS Notes (unsecured)	5.65%		2017	125.0	—
	1.65%		2018	250.0	—
	6.08%		2028	50.0	—
	5.55%		2036	125.0	—
	3.671%		2042	300.0	—
	4.752%		2044	450.0	—
Wisconsin Gas Debentures (unsecured)	5.20%		2015	—	125.0
	3.53%		2025	200.0	—
	5.90%		2035	90.0	90.0
PGL First and Refunding Mortgage Bonds (secured) [(1)]	2.21%		2016	50.0	—
	8.00%		2018	5.0	—
	4.63%		2019	75.0	—
	3.90%		2030	50.0	—
	1.875%		2033	50.0	—
	4.00%		2033	50.0	—
	4.30%		2035	50.0	—
	3.98%		2042	100.0	—
	3.96%		2043	220.0	—
	4.21%		2044	200.0	—
NSG First Mortgage Bonds (secured) [(2)]	3.43%		2027	28.0	—
	3.96%		2043	54.0	—
We Power Subsidiary Notes (secured, nonrecourse)	4.91%	[(3)]	2015-2030	112.1	117.2
	5.209%	[(4)]	2015-2030	215.0	223.9
	4.673%	[(4)]	2015-2031	178.3	184.7
	6.00%	[(3)]	2015-2033	130.5	134.6

	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	—
Integrys Junior Notes (unsecured)	6.11%		2066	269.8	—
	6.00%		2073	400.0	—

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Other Notes (secured, nonrecourse)	4.81%	2030	2.0	2.0
Obligations under capital leases			59.9	84.5
Total long-term debt and capital lease obligations			9,314.6	4,636.9
Integrys acquisition fair value adjustment			41.1	—
Unamortized debt issuance costs			(37.8)	(15.7)
Unamortized discount, net and other			(36.1)	(26.4)
Total			9,281.8	4,594.8
Current portion of long-term debt and capital lease obligations			(157.7)	(424.1)
Total long-term debt and capital lease obligations			9,124.1	4,170.7
Total long-term capitalization			$17,809.3	$8,620.8

(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 Wisconsin Electric related to PWGS 1 and 2.

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

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

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H. 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, Acquisition, 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 Wisconsin Electric, Wisconsin Gas, and WPS, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin. Wisconsin Electric'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 Wisconsin Electric.

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

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) Reclassifications—On the income statements for the years ended December 31, 2014 and 2013, we reclassified $17.4 million and $48.0 million, respectively, from treasury grant to depreciation and amortization. We also reclassified $1.2 million from interest expense to preferred stock dividends of subsidiaries on the income statements for the years ended December 31, 2014 and 2013. These reclassifications were made to be consistent with the current year presentation on the income statements.

During the fourth quarter of 2015, we early implemented ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. As a result, debt issuance costs of $15.7 million, previously reported as other long-term assets, were reclassified to offset long-term debt on the December 31, 2014 balance sheet. We also early implemented ASU 2015-17, Balance Sheet Classification of Deferred Taxes, during the fourth quarter of 2015. Since we adopted this ASU on a retrospective basis, we reclassified current deferred income taxes of $242.7 million, previously reported as a separate component of current assets, to offset long-term deferred income tax liabilities on the December 31, 2014 balance sheet.

On the statements of cash flows for the years ended December 31, 2014 and 2013, we reclassified $2.4 million and $4.2 million, respectively, from depreciation and amortization to other operating activities. In addition, we reclassified $13.9 million and

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$22.8 million of nonqualified pension and OPEB contributions from other operating activities to contributions to pension and OPEB plans on the statements of cash flows for the years ended December 31, 2014 and 2013, respectively. Preferred stock dividends of subsidiaries of $1.2 million were also reclassified from other financing activities to net income on the statements of cash flows for the years ended December 31, 2014 and 2013. These reclassifications were made to be consistent with the current year presentation on the statements of cash flows.

During the third quarter of 2015, following the acquisition of Integrys, we reorganized our business segments. All prior period amounts impacted by this change were reclassified to conform to the new presentation. See Note 24, Segment Information, for more information on our business segments.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

(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 return on common equity than authorized by the PSCW.

- Wisconsin Electric 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, and Note 23, Michigan Settlement, 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 Wisconsin Electric and Wisconsin Gas, 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.

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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 AMRP 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

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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 revenue. 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.

ITF accounts for revenues from construction management projects using the percentage of completion method. Revenues are recognized based on the percentage of costs incurred to date compared to the total estimated costs of each contract. This method is used because management considers total costs to be the best available measure of progress on these contracts. See Note 3, Dispositions, for more information.

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 Wisconsin Electric, Wisconsin Gas, 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, 2015. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2015.

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

(in millions)	2015	2014
Natural gas in storage	$284.1	$124.8
Materials and supplies	219.2	150.2
Fossil fuel	183.7	125.6
Total	$687.0	$400.6

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the Last-in, First-out (LIFO) cost method. Inventories stated on a LIFO basis represented approximately 18.0% of total inventories at December 31, 2015. The estimated replacement cost of natural gas in inventory at December 31, 2015, exceeded the LIFO cost by $15.2 million. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $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. It holds investments that are classified as trading securities for accounting purposes. We do not intend to sell these investments in the near term. They are included in other investments on our balance sheet at December 31, 2015. The net unrealized loss included in earnings related to the investments held at the end of the period was not significant for the year ended December 31, 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 revenue 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 capitalized interest. Utility property also includes AFUDC – Equity. 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.

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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	2015	2014	2013
Wisconsin Electric	3.01%	2.93%	2.90%
WPS (1)	1.30%	N/A	N/A
Wisconsin Gas	2.36%	2.69%	2.68%
PGL (1)	1.67%	N/A	N/A
NSG (1)	1.22%	N/A	N/A
MERC (1)	1.26%	N/A	N/A
MGU (1)	1.32%	N/A	N/A

(1) The rates shown for 2015 are for a partial year as a result of the acquisition of Integrys on June 29, 2015. 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 OC 1 and OC 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 Wisconsin Electric, WPS, and Wisconsin Gas. Approximately 50% of Wisconsin Electric's, WPS's, and Wisconsin Gas's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. For 2015, Wisconsin Electric's average AFUDC retail rate was 8.45%, and its average AFUDC wholesale rate was 1.72%. For the six months ended December 31, 2015, WPS's average AFUDC retail rate was 7.92% and its average AFUDC wholesale rate was 5.04%. For 2015, Wisconsin Gas's average AFUDC retail rate was 8.33%. 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 2015, 2014, or 2013.

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

(in millions)	2015	2014	2013
AFUDC – Debt	$8.6	$2.3	$7.7
AFUDC – Equity	$20.1	$5.6	$18.3

(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.

Our reporting units containing goodwill perform annual goodwill impairment tests during the third quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 10, Goodwill and Other Intangible Assets, for more information.

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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 the PTF 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 the PTF 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. A 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 AROs are accreted to their present value each period using the credit-adjusted risk-free interest rate associated with the expected settlement dates of the AROs. This rate is determined when the obligation is 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 18, Commitments and Contingencies, for more information.

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.

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(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 stockholder approved plans, we provide long-term incentives through our equity interests to our outside directors, officers, and other key employees. The plans provide for the granting of stock options, restricted stock awards, performance shares, and other share-based awards. Awards may be paid in common stock, cash, or a combination thereof. We recognize share-based compensation expense on a straight-line basis. Accordingly, for employee awards classified as equity awards, share-based compensation expense is measured based on the grant-date fair value of the award and is recognized as expense ratably over the requisite service period.

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 grant. There were no modifications to the terms of outstanding stock options during the year.

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:

	2015	2014	2013
Non-qualified stock options granted	516,475	899,500	1,418,560
Estimated fair value per non-qualified stock option	$5.29	$4.18	$3.45
Assumptions used to value the options:			
Risk-free interest rate	0.1% – 2.1%	0.1% – 3.0%	0.1% – 1.9%
Dividend yield	3.7 %	3.8 %	3.7 %
Expected volatility	18.0 %	18.0 %	18.0 %
Expected forfeiture rate	2.0 %	2.0 %	2.0 %
Expected life (years)	5.8	5.8	5.9

The risk-free interest rate is based on the U.S. Treasury interest rate with a term consistent with the expected life of the stock options. Dividend yield, expected volatility, expected forfeiture rate, and expected life assumptions are 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. During the vesting period, restricted share recipients also have voting rights and are entitled to dividends in the same manner as other shareholders.

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 stockholder return (stock price appreciation plus dividends) as compared to the total stockholder return of a peer group of companies over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash and are accounted for as liability awards accordingly. We accrue compensation costs over the three-year performance period based on our estimate of the final expected value of the awards.

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See Note 11, Common Equity, for more information on our share-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 by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. Options to purchase 516,475 shares of common stock with an exercise price of $52.90 were outstanding at December 31, 2015, but were not included in the computation of diluted earnings per share because they were anti-dilutive. All stock options outstanding during 2014 and 2013 were included in the computation of diluted earnings per share.

(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, 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 perpetual dividend discount model. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases, is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows.

We conduct a thorough review of fair value hierarchy classifications on a quarterly basis.

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.

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We record derivative instruments on our balance sheets as an asset or liability 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. 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. 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—ACQUISITION

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 and CNG products and services. Integrys also held a 34% interest in ATC, a for-profit transmission company regulated by the FERC. The acquisition of Integrys provides increased scale, the potential for long-term cost savings through a combination of lower capital and operating costs, and the potential for operating efficiencies.

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

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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. The fair values of Integrys's assets and liabilities subject to rate-setting provisions provide revenues derived from costs, including a return on investment of assets and 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 and Other Intangible Assets, for the allocation of goodwill to our reportable segments.

The table below shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition. The allocation is subject to change during the remainder of the measurement period, which ends one year from the acquisition date, as we obtain additional information, including with respect to certain regulatory and legal matters and the expected sale of ITF.

(in millions)		
Current assets	$1,069.9	
Net property, plant, and equipment	7,091.8	
Investments *	1,062.5	
Goodwill	2,581.6	
Deferred charges and other assets, excluding goodwill	1,737.9	
Current liabilities, including current maturities of long-term debt	(1,293.5	)
Deferred credits and other liabilities	(3,668.5	)
Long-term debt	(2,947.5	)
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 is permitted for any interim and annual financial statements that have 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.

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The PSCW order includes the following conditions:

- Wisconsin Electric and Wisconsin Gas will be subject to an earnings sharing mechanism for three years beginning January 1, 2016. Under the earnings sharing mechanism, 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 Wisconsin Electric, the additional utility earnings will be used to reduce the company's transmission escrow. For Wisconsin Gas, additional utility earnings will be used to reduce the costs of the Western Gas Lateral. All utility earnings above the first 50 basis points will be used to reduce the transmission escrow for Wisconsin Electric and reduce the costs of the Western Gas Lateral for Wisconsin Gas.
- 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 Wisconsin Electric 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 $107.6 million and $12.5 million during 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. No acquisition costs were recorded in 2013.

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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 payments of $16.9 million were made during 2015, leaving a severance accrual of $8.0 million on our balance sheet at December 31, 2015. Severance costs to be incurred after December 31, 2015 are not expected to be material. The severance expense was recorded in the following segments:

(in millions)	2015
Wisconsin	$11.1
Illinois	0.9
Other states	0.1
Corporate and other	12.8
Total severance expense	$24.9

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

NOTE 3—DISPOSITIONS

Corporate and Other Segment – Pending Sale of Integrys Transportation Fuels

In February 2016, we reached an agreement to sell ITF. The sale is scheduled to close in the first quarter of 2016. ITF is a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation and maintenance. The pending 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 pending sale of ITF does not represent a shift in our corporate strategy and will not have a major effect on our operations and financial results. Therefore, ITF's results of operations remain in continuing operations. The pre-tax profit or loss of this individually significant component was not material for the year ended December 31, 2015.

In November 2015, we sold our 30% joint interest in AMP Trillium LLC. This transaction was not significant, and there was no gain recorded on the sale. In addition, in the fourth quarter of 2015, we lowered the fair value of the remaining ITF assets to fair market value, less costs to sell. This fair value adjustment was reflected in the allocation of the purchase price for the acquisition. See Note 2, Acquisition, for more information.

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.

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NOTE 4—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

Due to the acquisition of Integrys on June 29, 2015, our ownership of ATC increased from 26.2% to approximately 60%. ATC is a for-profit, transmission-only company regulated by the FERC. 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)	2015	2014	2013
Balance at beginning of period	$424.1	$402.7	$378.3
Add: Earnings from equity method investment	96.1	66.0	68.5
Add: Capital contributions	8.7	13.1	10.5
Add: Acquisition of Integrys's investment in ATC	541.5	—	—
Add: Equity method goodwill from the acquisition of Integrys *	395.8	—	—
Less: Distributions received	85.1	57.5	54.5
Less: Other	0.2	0.2	0.1
Balance at end of period	$1,380.9	$424.1	$402.7

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

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 is reimbursed to us 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)	2015	2014	2013
Charges to ATC for services and construction	$15.4	$8.1	$9.0
Charges from ATC for network transmission services	289.2	231.4	234.2

As of December 31, 2015 and 2014, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2015	2014
Accounts receivable		
Services provided to ATC	$1.0	$0.6
Accounts payable		
Services received from ATC	28.3	19.3

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

(in millions)	2015	2014	2013
Income statement data			
Revenues	$615.8	$635.0	$626.3
Operating expenses	319.3	307.4	295.0
Other expense	96.1	88.9	83.7
Net income	$200.4	$238.7	$247.6

(in millions)	December 31, 2015	December 31, 2014
Balance sheet data		
Current assets	$80.5	$66.4
Noncurrent assets	3,957.6	3,728.7
Total assets	$4,038.1	$3,795.1

Current liabilities	$330.3	$313.1
Long-term debt	1,800.0	1,701.0
Other noncurrent liabilities	245.0	163.8
Shareholders' equity	1,662.8	1,617.2
Total liabilities and shareholders' equity	$4,038.1	$3,795.1

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NOTE 5—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2015	2014	2013
Cash paid for interest, net of amount capitalized	$329.6	$241.1	$250.4
Cash paid (received) for income taxes, net of refunds	9.3	22.0	(39.6)
Significant non-cash transactions:			
Construction costs funded through accounts payable	177.1	1.8	4.7
Amortization of deferred revenue	39.9	55.7	56.5
Note receivable received related to the sale of AMP Trillium*	12.0	—	—
Capital assets received related to the sale of AMP Trillium *	6.3	—	—

* See Note 3, Dispositions, for more information.

At December 31, 2015, restricted cash of $118.4 million was recorded within other long-term assets on our balance sheet. 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.

NOTE 6—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2015	2014	See Note
Regulatory assets (1) (2)			
Unrecognized pension and OPEB costs (3)	$1,306.4	$669.1	17
Environmental remediation costs (4)	697.0	45.9	18
Income tax related items (5)	248.3	176.0	
Electric transmission costs (6)	191.5	146.0	
AROs	173.0	17.6	9
SSR	86.1	—	22
Derivatives	70.4	14.7	1(t)
Energy efficiency programs (7)	48.7	58.0	
PTF (8)	45.4	66.6	
Other, net	234.9	77.3	
Total regulatory assets	$3,101.7	$1,271.2	
Balance Sheet Presentation			
Current assets (9)	$37.1	$—	
Regulatory assets	3,064.6	1,271.2	
Total regulatory assets	$3,101.7	$1,271.2	

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

(2) As of December 31, 2015, we had $33.8 million of regulatory assets not earning a return and $136.6 million of regulatory assets earning a return based on short-term interest rates.

(3) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans.

(4) As of December 31, 2015, we had not yet made cash expenditures for $628.2 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(5) Adjustments related to deferred income taxes. As the related temporary differences reverse, we prospectively collect taxes from customers for which deferred taxes were recorded in prior years.

(6) Represents amounts recoverable from customers related to transmission costs incurred that exceed amounts authorized for recovery in our current rates.

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(7) Represents amounts recoverable from customers related to programs at the utility subsidiaries designed to meet energy efficiency standards.

(8) Represents amounts recoverable from customers related to Wisconsin Electric's costs of the PTF units, including subsequent capital additions.

(9) Short-term regulatory assets are recorded in accounts receivable and accrued unbilled revenues on our balance sheets.

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

(in millions)	2015	2014	See Note
Regulatory liabilities			
Removal costs (1)	$1,209.6	$741.1	
Energy costs refundable through rate adjustments (2)	76.9	18.9	
Uncollectible expense (3)	31.8	30.1	
Mines deferral (4)	31.6	—	
Unrecognized pension and OPEB costs (5)	26.3	3.8	17
Other, net	49.8	36.7	
Total regulatory liabilities	$1,426.0	$830.6	
Balance Sheet Presentation			
Other current liabilities	$33.8	$—	
Regulatory liabilities	1,392.2	830.6	
Total regulatory liabilities	$1,426.0	$830.6	

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

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

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

(4) Represents the deferral of margins from the 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.

(5) Represents the unrecognized future OPEB costs resulting from actuarial gains on OPEB plans. We will amortize this regulatory liability into net periodic benefit cost over the average remaining service life of each plan.

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)	2015	2014
Utility property, plant, and equipment	$22,803.7	$12,290.7
Less: Accumulated depreciation	7,358.2	4,044.6
Net	15,445.5	8,246.1
CWIP	672.7	170.1

Net utility property, plant, and equipment	16,118.2	8,416.2
Non-utility and other property, plant, and equipment	3,482.2	3,260.3
Less: Accumulated depreciation	560.9	440.5
Net	2,921.3	2,819.8
CWIP	150.2	21.7
Net non-utility and other property, plant, and equipment	3,071.5	2,841.5
Total property, plant, and equipment	$19,189.7	$11,257.7

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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 the Oak Creek Expansion units to Wisconsin Electric, and Wisconsin Electric operates these units. Wisconsin Electric 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. Wisconsin Electric'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, 2015 was as follows:

(in millions, except for percentages and MWs)	We Power Oak Creek Expansion Units 1 and 2		WPS Weston 4		Columbia Energy Center Units 1 and 2		Edgewater Unit 4	
Ownership	83.34	%	70.0	%	31.8	%	31.8	%
Share of rated capacity (MWs) *	1,056.8		374.5		352.9		96.3	
In-service date	2010 and 2011		2008		1975 and 1978		1969	
Property, plant, and equipment	$2,359.6		$591.5		$404.6		$47.6	
Accumulated depreciation	$(283.4	)	$(150.5	)	$(122.6	)	$(30.6	)
CWIP	$35.5		$5.9		$23.4		$0.4	

* Based on expected capacity ratings for summer 2016. 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.

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. The utilities establish regulatory assets and liabilities 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. PDL has AROs recorded 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:

(in millions)	2015		2014		2013	
Balance as of January 1	$43.6		$42.3		$44.3	
Integrys subsidiaries	491.0		—		—	
Accretion	14.5		2.4		2.4	
Additions and revisions to estimated cash flows	35.5	*	—		—	
Liabilities settled	(13.4	)	(1.1	)	(4.4	)

Balance as of December 31	$571.2	$43.6	$42.3

* An ARO of $16.1 million was recorded during 2015 for fly-ash landfills located at generation facilities owned by Wisconsin Electric and WPS. An ARO of $9.0 million was also recorded for the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities rule passed by the EPA in April 2015. See Note 18, Commitments and Contingencies, for more information on this rule. 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.

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NOTE 10—GOODWILL AND OTHER INTANGIBLE ASSETS

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, 2015 and 2014:

	Wisconsin		Illinois		Other States		Total	
(in millions)	2015	2014	2015	2014	2015	2014	2015	2014
Balance as of January 1								
Gross goodwill	$441.9	$441.9	$—	$—	$—	$—	$441.9	$441.9
Accumulated impairment losses	—	—	—	—	—	—	—	—
Net goodwill as of January 1	441.9	441.9	—	—	—	—	441.9	441.9
Acquisition of Integrys	1,667.6	—	731.2	—	182.8	—	2,581.6	—
Balance as of December 31								
Gross goodwill	2,109.5	441.9	731.2	—	182.8	—	3,023.5	441.9
Accumulated impairment losses	—	—	—	—	—	—	—	—
Net goodwill as of December 31	$2,109.5	$441.9	$731.2	$—	$182.8	$—	$3,023.5	$441.9

In the third quarter of 2015, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of August 31, 2015. No impairments resulted from these tests.

The identifiable intangible assets other than goodwill listed below are part of other long-term assets on our balance sheets. We had no material intangible assets other than goodwill at December 31, 2014.

	December 31, 2015		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets (1)	$16.0	$(7.8)	$8.2
Unamortized intangible assets (2)	5.7	—	5.7
Total intangible assets	$21.7	$(7.8)	$13.9

(1) Primarily relates to contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at WPS's Fox Energy Center. The remaining weighted-average amortization period for our amortized intangible assets at December 31, 2015, was approximately three years.

(2) Consists primarily of a trade name.

NOTE 11—COMMON EQUITY

Share-Based Compensation Plans

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

(in millions)	2015	2014	2013
Stock options	$3.3	$3.7	$3.9
Restricted stock	7.0	2.8	2.4

Performance units	13.0	15.4	12.7
Share-based compensation expense	$23.3	$21.9	$19.0
Related tax benefit	$9.3	$8.8	$7.6

Stock-based compensation capitalized was not significant during 2015, 2014, and 2013.

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Stock Options

The following is a summary of our stock option activity during 2015:

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, 2015	6,770,194	$ 29.99		
Granted	516,475	$ 52.90		
Exercised	(1,302,005)	$ 23.09		
Outstanding as of December 31, 2015	5,984,664	$ 33.47	5.6	$107.6
Exercisable as of December 31, 2015	3,280,334	$ 26.84	3.9	$80.3

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, 2015. This is calculated as the difference between our closing stock price on December 31, 2015, 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, 2015, 2014, and 2013 was $36.1 million, $50.5 million, and $44.5 million, respectively. Cash received from options exercised during the years ended December 31, 2015, 2014, and 2013, was $30.1 million, $50.3 million, and $48.5 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $14.5 million, $19.9 million, and $17.8 million, respectively.

At December 31, 2015, total compensation cost related to non-vested stock options not yet recognized was approximately $1.5 million, which is expected to be recognized over the next 19 months on a weighted-average basis. During the first quarter of 2016, the Compensation Committee awarded 752,085 non-qualified stock options with a weighted-average exercise price of $51.80 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 2015:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2015	155,479	$ 38.45
Granted	143,107	$ 51.13
Released	(68,429)	$ 36.95
Forfeited	(1,139)	$ 46.26
Outstanding as of December 31, 2015	229,018	$ 46.78

On July 31, 2015, the Compensation Committee awarded certain of our officers and other employees an aggregate of 82,943 shares of restricted stock for the key role each played in our acquisition of Integrys. The restricted stock vests in three equal installments on January 29, 2016, January 31, 2017, and July 31, 2018.

The intrinsic value of restricted stock released was $3.7 million, $2.7 million, and $4.0 million for the years ended December 31, 2015, 2014, and 2013, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was $1.3 million, $1.0 million, and $1.3 million, respectively.

As of December 31, 2015, total compensation cost related to restricted stock not yet recognized was approximately $3.1 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

During the first quarter of 2016, the Compensation Committee awarded 113,892 restricted shares to certain of our directors, officers, and other key employees under its normal schedule of awarding long-term incentive compensation.

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Performance Units

In January 2015, 2014, and 2013, the Compensation Committee awarded 195,365; 233,735; and 239,120 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units earned as of December 31, 2015, 2014, and 2013 vested and were settled during the first quarter of 2016, 2015, and 2014, and had a total intrinsic value of $13.2 million, $13.2 million, and $14.8 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units for the same years was approximately $4.5 million, $4.8 million, and $5.3 million, respectively.

As of December 31, 2015, total compensation cost related to performance units not yet recognized was approximately $11.8 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

During the first quarter of 2016, the Compensation Committee awarded 283,505 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, Wisconsin Electric, Wisconsin Gas, 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.

Wisconsin Electric may not pay common dividends to us under Wisconsin Electric's Restated Articles of Incorporation if any dividends on its outstanding preferred stock have not been paid. In addition, pursuant to the terms of Wisconsin Electric's 3.60% Serial Preferred Stock, Wisconsin Electric'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.

Integrys has long-term debt obligations that contain financial and other covenants, including, but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%.

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.
We and Integrys have the option to defer interest payments on our Junior Notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our 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, 2015, 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 $6.2 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2015.

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

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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 2015, 2014, or 2013, other than for the Integrys acquisition discussed below.

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:

	2015		2014		2013	
(in millions)	Shares	Cost	Shares	Cost	Shares	Cost
Under share repurchase programs	—	$—	0.4	$18.6	3.0	$126.0
To fulfill exercised stock options and restricted stock awards	1.5	74.7	2.3	104.6	2.4	97.4
Total	1.5	$74.7	2.7	$123.2	$5.4	$223.4

Integrys Acquisition

On June 29, 2015, we issued approximately 90.2 million common shares to acquire Integrys. All Integrys unvested stock-based compensation awards became fully vested upon the close of the transaction and were paid to award recipients in cash or deferred into a deferred compensation plan. In addition, all vested but unexercised Integrys stock options were paid in cash. See Note 2, Acquisition, for more information on this acquisition.

Common Stock Dividends

During the year ended December 31, 2015, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 15, 2015	March 1, 2015	$0.4225	First quarter
April 16, 2015	June 1, 2015	$0.4225	Second quarter
June 12, 2015 (1)	July 6, 2015 (2)	$0.2067	45 days through June 28, 2015
June 12, 2015 (1)	September 1, 2015 (3)	$0.2337	47 days through Aug. 14, 2015
October 15, 2015	December 1, 2015	$0.4575	Fourth quarter

(1) Pro rata dividends were declared on June 12, 2015, in anticipation of closing the acquisition of Integrys.

(2) The dividend payable on July 6, 2015, was based on a quarterly rate of $0.4225 per share.

(3) The dividend payable on September 1, 2015, was based on our new quarterly rate of $0.4575 per share, which represents an 8.3% increase over the prior quarterly rate. Pursuant to the terms of the Merger Agreement, our Board of Directors adopted a new dividend policy.

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NOTE 12—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2015 and 2014:

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	—	—	$—
Wisconsin Electric				
$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

2014 (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	—	—	$—
Wisconsin Electric				
$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	—	—	—
Total				$30.4

On November 13, 2015, WPS redeemed all 511,882 outstanding shares of its five series of preferred stock: (i) 131,916 shares of 5.00% Series; (ii) 29,983 shares of 5.04% Series; (iii) 49,983 shares of 5.08% Series; (iv) 150,000 shares of 6.76% Series; and (v) 150,000 shares of 6.88% Series. The aggregate redemption price was $52.7 million, plus accumulated and unpaid dividends.

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

(in millions, except percentages)	2015 Balance	2014 Balance
Commercial paper		
Amount outstanding at December 31	$1,095.0	$617.6

Average interest rate on amounts outstanding at December 31	0.68 %	0.22 %
Average amounts outstanding during the year *	817.8	468.1

* Based on daily outstanding balances during the year.

WEC Energy Group, Wisconsin Electric, WPS, Wisconsin Gas, and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require us to maintain, subject to certain exclusions, a minimum total funded

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debt to capitalization ratio of less than 70.0%, 65.0%, 65.0%, 65.0%, and 65.0% respectively. All companies are in compliance with their respective ratio.

As of December 31, 2015, we had $1,387.0 million of available capacity under our bank back-up credit facilities and $1,095.0 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	2015
WEC Energy Group	December 2020	$1,050.0
Wisconsin Electric	December 2020	500.0
WPS *	December 2016	250.0
Wisconsin Gas	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		$18.0
Commercial paper outstanding		1,095.0
Available capacity under existing agreements		$1,387.0

*WPS plans to request approval from the PSCW to extend the maturity through December 2020.

In December 2015, WEC Energy Group, Wisconsin Electric, and Wisconsin Gas amended their credit facilities to extend their expirations to December 2020. At the same time, WPS and PGL terminated their prior credit facilities and entered into new credit facilities. The lenders under the WPS facility have agreed that its maturity can be extended to December 2020, subject to the receipt of PSCW approval. 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.

Our outstanding long-term debt, including current maturities as of December 31, 2015, included approximately $3.0 billion of Integrys debt assumed on June 29, 2015. The amount assumed included $46.2 million of fair value adjustments recorded in connection with purchase accounting, which will be amortized over the estimated remaining life of the debt and will not be a part of future principal payments. See Note 2, Acquisition, for more information regarding the acquisition.

WEC Energy Group

In June 2015, we issued $300.0 million of 1.65% Senior Notes due June 15, 2018, $400.0 million of 2.45% Senior Notes due June 15, 2020, and $500.0 million of 3.55% Senior Notes due June 15, 2025. The net proceeds were used to pay a portion of the cash consideration for the acquisition of Integrys and related transaction costs, and for general corporate purposes.

Wisconsin Electric Power Company

In May 2015, Wisconsin Electric issued $250.0 million of 3.10% Debentures due June 1, 2025. The net proceeds were used to repay short-term debt and for general corporate purposes.

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In November 2015, Wisconsin Electric issued $250.0 million of 4.30% Debentures due December 15, 2045. The proceeds were used to repay short-term debt, to repay a portion of Wisconsin Electric’s $250.0 million of 6.25% Debentures that matured on December 1, 2015, and for working capital and general corporate purposes.

Wisconsin Public Service Corporation

In November 2015, WPS redeemed all of the remaining $0.1 million aggregate principal amount of First Mortgage Bonds, 7.125% Series due July 1, 2023 at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest to the date of redemption. Following the redemption, WPS discharged its mortgage indenture and does not intend to issue additional first mortgage bonds. All of WPS's senior notes outstanding are now senior unsecured obligations and rank equally with all of its other unsecured obligations.

In December 2015, WPS's $125.0 million of 6.375% Senior Notes matured, and the outstanding principal balance was repaid.

In December 2015, WPS issued $250.0 million of 1.65% Senior Notes due December 4, 2018. The proceeds were used to repay short-term debt incurred to repay all of WPS's $125.0 million of 6.375% Senior Notes at maturity, and for working capital and general corporate purposes.

Wisconsin Gas

In September 2015, Wisconsin Gas issued $200.0 million of 3.53% Debentures due September 30, 2025. The net proceeds were used to repay short-term debt and for general corporate purposes.

In December 2015, Wisconsin Gas's $125.0 million of 5.20% Debentures matured, and the outstanding principal balance was repaid.

The Peoples Gas Light and Coke Company

In August 2015, the interest rate on PGL's $50.0 million of 2.625% Series WW Bonds was reset. The new interest rate is 1.875%. The new mandatory interest reset date is August 1, 2020. The final maturity of these bonds is February 1, 2033.

In November 2016, PGL's 2.21% First and Refunding Mortgage Bonds will mature. As a result, the $50.0 million balance of these bonds was included in the current portion of long-term debt on our balance sheet at December 31, 2015.

W.E. Power

During 2016, $5.4 million of We Power's outstanding $112.1 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, 2015.

During 2016, $4.4 million of We Power's outstanding $130.5 million of 6.00% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2015.

During 2016, $10.2 million of We Power's outstanding $215.0 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, 2015.

During 2016, $7.4 million of We Power's outstanding $178.3 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, 2015.

Integrys Holding

In July 2015, Integrys tendered an offer to repurchase all $55.0 million outstanding of its 8.00% Senior Notes due June 1, 2016, and $5.0 million of this amount was tendered and purchased. The $50.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at December 31, 2015.

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Bonds and Notes

The following table shows the future maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) as of December 31, 2015:

(in millions)	Payments
2016	$127.4
2017	154.5
2018	836.1
2019	357.7
2020	684.4
Thereafter	7,094.6
Total	$9,254.7

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in an outstanding principal amount of $147.0 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2015 and 2014, the repurchased bonds were still outstanding, but were not reported in our consolidated long-term debt or included on our capitalization statements because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

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 $500.0 million of 6.25% Junior Notes will bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 211.25 basis points and will reset quarterly.

In connection with Integrys's outstanding 2006 6.11% Junior Subordinated Notes (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.

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. Effective December 1, 2016, the remaining $114.9 million aggregate principal amount of the 6.11% Junior Notes will bear interest at the three-month LIBOR rate plus 212 basis points and will reset quarterly.

In connection with the transaction, Integrys issued approximately $66.4 million of additional common stock to WEC Energy Group in satisfaction of its obligations under the Integrys RCC.

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 Rate plus 322 basis points and will reset quarterly.

Certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

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Obligations Under Capital Leases

In 1997, Wisconsin Electric 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 no minimum energy requirements. When the contract expires in 2022, Wisconsin Electric may, at its option and with proper notice, renew for another ten 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 $36.2 million and $34.9 million in lease payments during 2015 and 2014, 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 $59.9 million as of December 31, 2015, 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)	2015	2014
Long-term power purchase commitment	$140.3	$140.3
Accumulated amortization	(103.9)	(98.3)
Total leased facilities	$36.4	$42.0

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2015 are as follows:

(in millions)	Payments
2016	$45.1
2017	13.9
2018	14.7
2019	15.5
2020	16.4
Thereafter	24.9
Total minimum lease payments	130.5
Less: Estimated executory costs	(47.4)
Net minimum lease payments	83.1
Less: Interest	(23.2)
Present value of net minimum lease payments	59.9
Less: Due currently	(30.3)
Long-term obligations under capital lease	$29.6

NOTE 15—INCOME TAXES

Income Tax Expense

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

(in millions)	2015	2014	2013

Current tax expense	$15.1	$33.6	$25.2
Deferred income taxes, net	420.4	329.2	313.8
Investment tax credit, net	(1.7)	(1.1)	(1.1)
Total income tax expense	$433.8	$361.7	$337.9

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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 U.S. statutory federal income tax rate to income before income taxes as a result of the following:

	2015		2014		2013	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	$375.5	35.0 %	$332.5	35.0 %	$320.3	35.0 %
State income taxes net of federal tax benefit	73.1	6.8 %	50.5	5.3 %	49.0	5.3 %
Production tax credits	(17.4)	(1.6)%	(17.4)	(1.8)%	(16.7)	(1.8)%
AFUDC – Equity	(7.1)	(0.7)%	(1.9)	(0.2)%	(6.4)	(0.7)%
Investment tax credit restored	(1.7)	(0.2)%	(1.1)	(0.1)%	(1.1)	(0.1)%
Treasury grant	(1.7)	(0.2)%	(3.8)	(0.4)%	(7.4)	(0.8)%
Other, net	13.1	1.3 %	2.9	0.2 %	0.2	— %
Total income tax expense	$433.8	40.4 %	$361.7	38.0 %	$337.9	36.9 %

Deferred Income Tax Assets and Liabilities

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

(in millions)	2015	2014
Deferred tax assets		
Future tax benefits	$382.8	$221.7
Employee benefits and compensation	229.9	111.9
Deferred revenues	219.9	221.3
Property-related	59.5	28.8
Other	177.1	118.4
Total deferred tax assets	1,069.2	702.1
Valuation allowance	(17.1)	—
Net deferred tax assets	$1,052.1	$702.1
Deferred tax liabilities		
Property-related	4,451.5	2,750.4
Employee benefits and compensation	428.9	242.5
Investment in transmission affiliate	420.4	188.6
Deferred transmission costs	76.7	58.5
Other	296.9	126.1
Total deferred tax liabilities	5,674.4	3,366.1
Deferred tax liability, net	$4,622.3	$2,664.0

Consistent with rate-making treatment, deferred taxes in the table above are offset for temporary differences that have related regulatory assets and liabilities.

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The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2015 and 2014 are summarized in the table below:

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)	

2014 (in millions)	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2014				
Federal net operating loss	$416.2	$145.7	$—	2029
Federal tax credit	—	76.0	—	2029
Balance as of December 31, 2014	$416.2	$221.7	$—	

Valuation allowances of approximately $17.1 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)	2015	2014
Balance as of January 1	$7.2	$8.4
Acquired legacy Integrys unrecognized tax benefits	3.6	—
Additions for tax positions of prior years	0.3	—
Additions based on tax positions related to the current year	0.2	—
Reductions for tax positions of prior years	(1.1)	(1.2)
Settlements during the period	(0.7)	—
Balance as of December 31	$9.5	$7.2

The amount of unrecognized tax benefits as of December 31, 2015 and 2014, excludes deferred tax assets related to uncertainty in income taxes of $6.2 million and $7.2 million, respectively. As of December 31, 2015, our effective tax rate could be affected by recognition of approximately $2.2 million of unrecognized tax benefits. As of December 31, 2014, there were no unrecognized tax benefits that, if recognized, would impact the effective tax rate.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the year ended December 31, 2015, we recognized no accrued interest in our income statements. For the years ended December 31, 2014 and 2013, we recognized approximately $0.3 million and $0.2 million, respectively, of accrued interest in our income statements. For the years ended December 31, 2015, 2014, and 2013, we recognized no penalties in our income statements. 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. For the year ended December 31, 2014, we had approximately $0.7 million of interest accrued and no penalties accrued on our balance sheets.

We do not anticipate any significant increases or decreases in the total amounts of unrecognized tax benefits within the next 12 months.

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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, 2015, we were subject to examination by state or local tax authorities for the 2008 through 2015 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Years
Federal	2012–2015
Illinois	2008–2015
Michigan	2008–2015
Minnesota	2011–2015
Wisconsin	2011–2015

NOTE 16—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at December 31, 2015	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees				
Guarantees supporting commodity transactions of subsidiaries (1)	$174.5	$95.0	$—	$79.5
Standby letters of credit (2)	28.4	18.5	9.7	0.2
Surety bonds (3)	38.6	38.6	—	—
Other guarantees (4)	70.5	20.6	0.1	49.8
Total guarantees	$312.0	$172.7	$9.8	$129.5

(1) Consists of (a) $5.0 million and $11.0 million to support the business operations of WBS and PDL, respectively; and (b) $117.6 million, $40.3 million, and $0.6 million related to natural gas supply at MERC, MGU, and ITF, respectively. These amounts are not reflected on our balance sheets.

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

(3) Primarily for the construction and operation of CNG fueling stations by ITF, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of (a) $19.1 million to support PDL's future payment obligations related to its distributed solar generation projects, of which $6.6 million is covered by a reciprocal guarantee from a third party; (b) $20.0 million for an interconnection agreement between WPS and ATC; (c) $10.0 million related to the sale of a nonregulated retail marketing business previously owned by Integrys; (d) $11.2 million related to the performance of an operating and maintenance agreement by ITF; and (e) $10.2 million related to other indemnifications. The amounts discussed in items (a), (b) and (d) are not reflected on our balance sheets. An insignificant liability was recorded for item (c) related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the law. In addition, a liability of $9.6 million related to workers compensation coverage was recorded for item (e).

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. Approximately half of the projected benefit obligation for legacy Wisconsin Energy Corporation employees relates to benefits 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) plan instead of being enrolled in the defined benefit plans.

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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) 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)	2015	2014	2015	2014
Change in benefit obligation				
Obligation at January 1	$1,505.5	$1,410.2	$397.7	$362.7
Obligation assumed from acquisition	1,594.0	—	493.0	—
Service cost	30.4	10.1	20.7	8.5
Interest cost	94.3	68.1	26.7	17.8
Participant contributions	—	—	12.7	9.1
Plan amendments	—	—	—	(4.6)
Actuarial loss (gain)	14.6	120.4	(74.0)	29.4
Benefit payments	(156.0)	(103.3)	(36.2)	(26.4)
Federal subsidy on benefits paid	N/A	N/A	1.6	1.2
Plan curtailment	0.2	—	(0.2)	—
Obligation at December 31	$3,083.0	$1,505.5	$842.0	$397.7
Change in fair value of plan assets				
Fair Value at January 1	$1,444.6	$1,451.0	$333.5	$327.6
Assets received from acquisition	1,420.9	—	442.1	—
Actual return on plan assets	(62.1)	88.5	(15.6)	17.7
Employer contributions	107.7	8.4	13.3	5.5
Participant contributions	—	—	12.7	9.1
Benefit payments	(156.0)	(103.3)	(36.2)	(26.4)
Fair value at December 31	$2,755.1	$1,444.6	$749.8	$333.5

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)	2015	2014	2015	2014
Other long-term assets	$74.1	$39.2	$50.1	$39.5
Pension and other postretirement benefit obligations *	402.0	100.1	142.3	103.7
Total net liabilities	$327.9	$60.9	$92.2	$64.2

* 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 pension plans was $2,936.4 million and $1,504.6 million as of December 31, 2015, and 2014, respectively.

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

(in millions)	2015	2014
Projected benefit obligation	$1,706.6	$100.1
Accumulated benefit obligation	1,560.5	99.8

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

	Pension Costs		OPEB Costs	
(in millions)	2015	2014	2015	2014
Accumulated other comprehensive loss (pre-tax) [1]				
Net actuarial loss (gain)	$11.4	$—	$(0.6)	$—
Total	$11.4	$—	$(0.6)	$—
Net regulatory assets [2]				
Net actuarial loss	$798.1	$622.7	$23.7	$44.1
Prior service costs (credits)	4.7	6.8	(3.3)	(4.6)
Total	$802.8	$629.5	$20.4	$39.5

[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 2016:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$41.6	$1.9
Prior service costs	1.7	(1.2)
Total 2016 – estimated amortization	$43.3	$0.7

The components of net periodic benefit cost for the years ended December 31 are as follows:

	Pension Costs			OPEB Costs		
(in millions)	2015	2014	2013	2015	2014	2013
Service cost	$30.4	$10.1	$14.6	$20.7	$8.5	$10.0
Interest cost	94.3	68.1	60.4	26.7	17.8	15.6
Expected return on plan assets	(155.6)	(98.6)	(95.8)	(39.6)	(23.7)	(21.3)
Plan curtailment	(0.3)	—	—	—	—	—
Amortization of prior service cost (credit)	2.2	2.1	2.3	(6.4)	(1.8)	(2.0)
Amortization of net actuarial loss	68.5	36.7	54.5	3.9	1.2	3.7
Settlement charge	—	—	2.5	—	—	—
Net periodic benefit cost	$39.5	$18.4	$38.5	$5.3	$2.0	$6.0

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

	Pension		OPEB	
	2015	2014	2015	2014
Discount rate	4.46%	4.15%	4.38%	4.20%
Rate of compensation increase	4.00%	4.00%	N/A	N/A
Assumed medical cost trend rate	N/A	N/A	7.50%	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

	2015	2014	2013
Discount rate	4.11%	5.00%	4.10%
Expected return on plan assets	7.37%	7.25%	7.25%
Rate of compensation increase	4.0%	4.0%	4.0%

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	OPEB Costs		
	2015	2014	2013
Discount rate	4.09%	4.95%	4.15%
Expected return on plan assets	7.54%	7.50%	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 2016, the expected return on assets assumption is 7.13% 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, 2015, 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	$6.5	$(5.3)
Effect on health care component of the accumulated postretirement benefit obligations	79.4	(65.9)

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.

Previously, the Wisconsin Energy Corporation pension trust target allocation was 45% equity investments and 55% fixed income investments. A transition to a target asset allocation of 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments began in late 2014. The Integrys pension trust target allocation moved from 70% equity investments and 30% fixed income investments in 2014 to 60% equity investments and 40% fixed income investments for 2015. The current OPEB trusts' target asset allocations are 60% equity investments and 40% fixed income investments for Wisconsin Energy Corporation, and 70% equity investments and 30% fixed income investments for Integrys. 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 U.S. 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.

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

	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	$45.8	$—	$62.8	$9.8	$1.3	$—	$11.1
Equity securities:								
U.S. Equity	524.1	291.0	—	815.1	146.4	136.3	—	282.7
International Equity	192.2	351.2	—	543.4	57.2	133.3	—	190.5
Fixed income securities: *								
U.S. Bonds	53.2	1,019.2	—	1,072.4	122.3	116.1	—	238.4
International Bonds	67.4	140.3	—	207.7	16.0	6.7	—	22.7
Private Equity and Real Estate	—	—	53.7	53.7	—	—	4.4	4.4
Total	$853.9	$1,847.5	$53.7	$2,755.1	$351.7	$393.7	$4.4	$749.8

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

	December 31, 2014							
	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	$6.4	$—	$—	$6.4	$1.4	$—	$—	$1.4
Equity securities:								
U.S. Equity	503.8	—	—	503.8	146.0	—	—	146.0
International Equity	128.6	29.8	—	158.4	42.2	2.5	—	44.7
Fixed income securities: *								
U.S. Bonds	42.5	599.3	—	641.8	3.5	112.4	—	115.9
International Bonds	79.3	43.3	—	122.6	17.5	7.0	—	24.5
Private Equity and Real Estate	—	—	11.6	11.6	—	—	1.0	1.0
Total	$760.6	$672.4	$11.6	$1,444.6	$210.6	$121.9	$1.0	$333.5

* This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. 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	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2015	$11.6	$1.0
Realized and unrealized gains (losses)	1.8	0.1
Purchases	51.1	4.2
Liquidations	(10.8)	(0.9)

Ending balance at December 31, 2015	$53.7	$4.4

	Private Equity and Real Estate	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2014	$—	$—
Purchases	11.6	1.0
Ending balance at December 31, 2014	$11.6	$1.0

Cash Flows

We expect to contribute $23.8 million to the pension plans and $6.9 million to OPEB plans in 2016, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

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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
2016	$305.7	$48.4
2017	215.4	53.4
2018	211.9	52.2
2019	223.2	54.7
2020	224.9	57.1
2021-2025	1,105.2	307.0

Savings Plans

We sponsor 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 through an employee stock ownership plan (ESOP) contribution or cash contribution up to certain limits. The ESOPs held 5.5 million shares of our common stock (market value of $280.6 million) at December 31, 2015. Certain employees participate in a defined contribution pension plan, in which amounts are contributed to an employee's account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $48.0 million in 2015 and $14.2 million in both 2014 and 2013.

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, environmental remediation, and enforcement and litigation matters.

Unconditional Purchase Obligations

Energy Related Purchased Power Agreements

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, 2015, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2016	2017	2018	2019	2020	Later Years
Electric utility:								
Purchased power	2027	$811.9	$110.1	$78.4	$74.9	$62.1	$62.4	$424.0
Coal supply and transportation	2019	608.7	310.2	177.4	110.0	11.1	—	—
Nuclear	2033	10,012.5	412.8	415.3	420.0	445.4	475.1	7,843.9
Natural gas utility supply and transportation	2028	1,244.6	331.6	263.6	200.1	159.3	115.2	174.8

Total	$12,677.7	$1,164.7	$934.7	$805.0	$677.9	$652.7	$8,442.7

Operating Leases

We lease various property, plant, and equipment with various terms in the operating leases. 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 $12.7 million, $4.8 million, and $4.0 million in 2015, 2014, and 2013, respectively.

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

Year Ending December 31	Payments (in millions)
2016	$9.8
2017	9.8
2018	9.0
2019	6.2
2020	5.7
Later years	66.6
Total	$107.1

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 new 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 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

Sulfur Dioxide National Air Ambient 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 latitude in rule implementation. States have the option of modeling or monitoring to show attainment (subject to EPA approval for this selection) and make attainment designation recommendations. If a state chooses modeling and an area does not show attainment, and sources do not agree to reductions by 2017 to allow attainment, the area would be classified as nonattainment. A plan would need to be developed requiring emission reductions to bring the area back into attainment by 2023. Alternatively, if a state opted out of modeling and instead chose to install air quality monitors, and subsequently monitored nonattainment, then it would face a 2026 compliance date. 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 requires the EPA to complete attainment designations for certain areas with large sources by no later than July 2, 2016. SO_2 emissions from PIPP are above the emission threshold, which means that the Marquette area requires action earlier than would otherwise be required under the revised NAAQS. However, we were able to show through modeling that the area should be designated as attainment. Based upon this modeling, the state of Michigan recommended to the EPA that the Marquette area be designated as attainment. We expect that the EPA will act on this recommendation in 2016.

We believe our fleet overall is well positioned to meet the new regulation.

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8-Hour Ozone National Air Ambient 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 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.

Mercury and Other Hazardous Air Pollutants

In December 2011, the EPA issued the final MATS rule, which imposes 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 United States Supreme Court (Supreme Court) ruled on a challenge to the MATS rule and remanded the case back to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals), ruling that the EPA failed to appropriately consider the cost of the regulation. The MATS rule has been remanded to the EPA to address the Supreme Court decision, but remains in effect while the EPA completes its cost evaluation.

Our compliance plans currently include capital projects for PIPP and for WPS's jointly owned plants to achieve the required reductions for MATS. Construction on the addition of a dry sorbent injection system for further control of mercury and acid gases at PIPP is essentially complete and going through final startup and tuning. In addition, construction of the ReACT™ multi-pollutant control system at Weston Unit 3 is complete and startup/commissioning work is underway with an expected in-service date of July 2016. Controls for acid gases and mercury are already in operation at the Pulliam units.

In April 2013, Wisconsin Electric received a one year MATS compliance extension from the MDEQ for PIPP through April 2016. Although WPS also received a one year MATS compliance extension from the WDNR for Weston Unit 3 through April 2016, this unit is shut down to complete the construction of the ReACT™ system.

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 as an alternative to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. The final rule for existing fossil generating units seeks to achieve state-specific GHG emission reduction goals by 2030, and requires states to submit plans by September 6, 2016. States submitting initial plans and requesting an extension would be required to submit final plans by September 2018, either alone or in conjunction with other states. States will be required to meet interim goals over the period from 2022 through 2029, and a final goal in 2030, with the goal of reducing 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. 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.

Rules for existing, as well as new, modified, and reconstructed generating units became effective in October 2015. A draft Federal Plan and Model Trading Rule 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 review to the EPA of the final standards for existing as well as new, modified, and reconstructed generating units. A petition for review was also submitted jointly by the Wisconsin utilities. The utilities' petition narrowly asks 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%. The state's petition asks for review of a number of aspects of the final rules, including an adjustment to reflect the Kewaunee Power Station retirement. In January 2016, we submitted comments on the draft Federal Plan and Model Trading Rule. Michigan state agencies announced modeling results that suggest that the state will be able to meet existing source requirements until 2025, based on planned coal plant retirements, along with a continuation of state renewable standards and current levels of energy efficiency. A stakeholder process began in the middle of January 2016. Michigan plans to submit an interim plan by September 6, 2016, with a request for a two year extension for submittal of a final plan.

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We are in the process of reviewing the final rule for existing generating units to determine the potential impacts to our operations. The rule could result in significant additional compliance costs, including capital expenditures, could impact how we operate our existing fossil-fueled power plants and biomass facility, and could have a material adverse impact on our operating costs. In October 2015, following publication of the final rule, 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 on February 9, 2016, the Supreme Court stayed the effectiveness of the rule until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that review is sought, at the Supreme Court. Therefore, it is unlikely that states will move forward on the development of state plans until the litigation is complete. In addition, on February 15, 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.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2014, Wisconsin Energy Corporation reported aggregated CO_2 equivalent emissions of approximately 23.3 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that WEC Energy Group will report CO_2 equivalent emissions of approximately 31.0 million metric tonnes to the EPA for 2015. 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 2014, Wisconsin Energy Corporation reported aggregated CO_2 equivalent emissions of approximately 10.8 million metric tonnes to the EPA related to our distribution and sale of natural gas. Based upon our preliminary analysis of the data, we estimate that WEC Energy Group will report CO_2 equivalent emissions of approximately 27.1 million metric tonnes to the EPA for 2015.

The increase in CO_2 equivalent amounts reported between 2014 and 2015 for the electric generating facilities, as well as the amounts related to the distribution and sale of natural gas, are primarily related to the addition of the Integrys regulated companies, which were acquired on June 29, 2015.

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 and entrainment. The rule became effective in October 2014, and applies to all of our existing generating facilities with cooling water intake structures, except for the Oak Creek expansion 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 VAPP Units 1 and 2, Pulliam Units 7 and 8, and Weston Unit 2, satisfy the IM BTA requirements. For VAPP Unit 2, a project to install fish protection screens to meet the IM BTA standard was completed in October 2015. The same types of screens are scheduled to be installed on VAPP Unit 1 starting in September 2016. 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 proposed 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, Port Washington Generating Station, Pleasant Prairie Power Plant, PIPP, and Oak Creek Power Plant Units 5 through 8.

During 2016–2018, we plan 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. In addition, the rule allows the EM BTA requirements to be waived in cases of pending facility retirements, which we are currently considering for PIPP. Based on discussions with the MDEQ, if we submit a signed certification with our next National Pollutant Discharge Elimination System permit application 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 will commence in January 2016 at PIPP.

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. Unless pending challenges to the final guidelines are successful, the WDNR and MDEQ will modify the state rules 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 likely require additional biological treatment capital improvements for the Oak Creek 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 also required by the new rule, and modifications will be required at Oak Creek Units 5 and 6, the Pleasant Prairie units, PIPP Units 5 through 9, 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 $70 million to $100 million for these biological treatment and bottom ash transport systems.

Valley Power Plant Wisconsin Pollution Discharge Elimination System Permit

The WDNR issued a WPDES permit for VAPP that became effective in January 2013. The permit contains several additional requirements including effluent toxicity testing and monitoring for additional parameters (phosphorous, mercury, and ammonia-nitrogen), and a new heat addition limit from the cooling water discharges that all took effect immediately. Other long-term compliance requirements include thermal discharge studies, phosphorous evaluation and feasibility for reduction, mercury minimization planning, and the installation of new cooling water intake fish protection screens. Installation of wedge wire screens for fish protection on the VAPP Unit 2 cooling water intake structure is complete. An identical modification is planned for VAPP Unit 1 in 2016. We are also currently involved in planning to meet the remaining long-term requirements.

Land Quality

Coal Combustion Residuals Rule

In April 2015, the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities final rule was entered into the Federal Register. The final rule regulates the disposal of coal combustion residuals as a non-hazardous waste. We do not expect the compliance costs will be significant because we currently have a program of beneficial utilization for most of our coal combustion products. If needed, we have landfill capacity that meets the rule requirements for our remaining coal combustion product sources.

Coal Combustion Product Landfill Sites

We aggressively seek environmentally acceptable, beneficial uses for our coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required some level of monitoring or remediation. Where we have become aware of these conditions, and where necessary, we have worked to define the nature and extent of the impact, if any, and work has been performed to address these conditions. During 2015, 2014, and 2013, landfill remediation expenses were not material. See Note 9, Asset Retirement Obligations, for more information about obligations related to these sites.

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Renewables, Efficiency, and Conservation

Wisconsin Act 141

In 2006, Wisconsin revised the requirements for renewable energy generation by enacting Act 141. Act 141 established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. Under Act 141, Wisconsin Electric and WPS are required to increase their renewable energy percentage to 8.27% and 9.74%, respectively. To comply with these requirements, Wisconsin Electric constructed the Blue Sky Green Field wind park, the Glacier Hills wind park, and the Rothschild biomass facility. WPS constructed the Crane Creek wind park. Wisconsin Electric and WPS also rely on renewable energy purchases to meet their respective renewable portfolio standard commitments.

Wisconsin Electric and WPS are in compliance with Act 141's 2015 standard and have entered into agreements for renewable energy credits, that should allow Wisconsin Electric and WPS to remain in compliance through 2022 and 2023, respectively. If market conditions are favorable, Wisconsin Electric and WPS may purchase more renewable energy credits. Act 141 assigned responsibility for the administration of energy efficiency, conservation, and renewable programs to the PSCW and/or contracted third parties. The funding required by Act 141 for 2015 was 1.2% of annual operating revenues of each utility.

Michigan Act 295

In 2008, Michigan revised the requirements for renewable energy generation by enacting Act 295. Act 295 requires 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. Wisconsin Electric and WPS are currently in compliance with this requirement. Act 295 specifically calls for current recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

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 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, some of these sites are coordinating the investigation and cleanup 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)	2015	2014
Regulatory assets	$697.0	$45.9
Reserves for future remediation	628.0	32.6

The increases in the regulatory assets and reserves are primarily related to balances associated with the Integrys regulated companies, which were acquired on June 29, 2015. See Note 2, Acquisition, for more information.

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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 Wisconsin Pollution Discharge Elimination System Permit

In November 2014, the WDNR reissued the WPDES permit for the PSGS. We believed that the WDNR imposed unreasonable permit conditions with respect to temperature monitoring, the control of water treatment additive, and phosphorus discharges. To address these permit conditions, Wisconsin Electric filed a petition for a contested case hearing with the WDNR in January 2015. On the same day, Wisconsin Electric also filed a request to be covered by the statewide phosphorus variance to address one of its concerns with the permit. Wisconsin Electric reached an agreement with the WDNR with respect to the permit conditions for temperature monitoring and for restrictions related to the use of a water treatment additive. In March 2015, the WDNR issued a final WPDES permit with agreed upon modifications, and Wisconsin Electric withdrew its petition for a contested case hearing. In July 2015, the Milwaukee County Circuit Court entered a stipulation and Order for Judgment between the WDNR and Wisconsin Department of Justice. This order resolves the litigation by allowing Wisconsin Electric to maintain the ability to apply for and be covered by the statewide phosphorus variance.

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 PSGS Units 1 and 4, allowing those units to restart after a temporary outage related to a construction permit matter with the WDNR. We received an “after the fact” permit from the WDNR, and the units are now available for service. 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 administration order issued in this matter, which was granted. However, a hearing has not yet been scheduled.

Valley Power Plant Title V Air Permit

In February 2011, the WDNR renewed VAPP's Title V operating permit for five years. In March 2011, the Sierra Club petitioned the EPA for additional reductions and monitoring for particulate matter and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition. In May 2012, the Sierra Club filed a notice of intent to bring suit to force the EPA to issue a response to that petition. We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of this proceeding the permit is remanded to the WDNR, the plant will continue to operate under the previous operating permit.

Weston Title V Air Permit

In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, WPS challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also challenged various aspects of the permit. The WDNR granted all parties' requests for contested case proceedings. The Petitions for Judicial Review, by all parties, have been stayed pending the resolution of the contested cases. In February 2014, a new permit change was challenged and added to the case. The ALJ dismissed some of the petition issues relating to the averaging period and monitoring issues.

In May 2014, the WDNR issued a Notice of Violation (NOV) alleging that WPS failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System certification and included an issue related to reporting NOx emissions from the Weston Unit 4 auxiliary boiler.

In June 2015, the WDNR issued a NOV alleging that WPS failed to comply with mercury reporting requirements related to challenged matters in the 2013 Weston Title V permit. The ALJ denied its request to issue a stay or confirm that a statutory stay applies to the requirements identified in the NOV.

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The contested case has been stayed for a period of months, and no hearing date has been set. We do not expect these matters to have a material impact on our financial statements.

Solvay Coke and Gas Site

In August 2004, Wisconsin Electric and Wisconsin Gas were identified as potentially responsible parties at the Solvay Coke and Gas Site located in Milwaukee, Wisconsin. A predecessor company of Wisconsin Electric owned a parcel of property that is within the property boundaries of the site. A predecessor company of Wisconsin Gas had a customer and corporate relationship with the entity that owned and operated the site. In 2007, Wisconsin Electric, Wisconsin Gas, and several other parties entered into an Administrative Settlement Agreement and Order with the EPA to perform additional investigation and assessment and reimburse the EPA's oversight costs. The final remedial investigation report was submitted to the EPA in December 2015, and work will now begin on the feasibility study. Under the Administrative Settlement Agreement, neither Wisconsin Electric nor Wisconsin Gas admits to any liability for the site, waives any liability defenses, or commits to perform future site remedial activities. The companies' share of the costs to perform the required work and reimburse the EPA's oversight costs, as well as potential future remediation cost estimates and reserves, are included in the estimated manufactured gas plant values reported above.

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 U.S. 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.

As mentioned above, the Consent Decree contains a requirement 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 and recorded a regulatory asset of $11.5 million for the undepreciated book value. WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant associated with these units starting June 1, 2015, and concluding by 2023.

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. The majority of the beneficial environmental projects proposed by WPS have been approved by the EPA. WPS is currently working with the EPA on certain changes to the environmental projects, but these changes are not expected to materially impact the overall cost.

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, 2015. It is unknown whether the Sierra Club will take further action in the future.

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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, Wisconsin Electric (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, Wisconsin Power and Light, Madison Gas and Electric, and Wisconsin Electric 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. Wisconsin Electric 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.

As mentioned above, the Consent Decree contains a requirement to 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. All of the beneficial environmental projects that WPS proposed have been approved by the EPA.

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, 2015			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	$1.6	$1.5	$—	$3.1
FTRs	—	—	3.6	3.6
Petroleum products contracts	1.2	—	—	1.2
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
Liabilities				
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

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	December 31, 2014			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	$1.1	$3.9	$—	$5.0
FTRs	—	—	7.0	7.0
Coal contracts	—	3.3	—	3.3
Total derivative assets	$1.1	$7.2	$7.0	$15.3
Liabilities				
Derivative liabilities				
Natural gas contracts	$11.5	$0.8	$—	$12.3
Coal contracts	—	0.2	—	0.2
Total derivative liabilities	$11.5	$1.0	$—	$12.5

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)	2015	2014	2013
Balance at the beginning of the period	$7.0	$3.5	$4.7
Realized and unrealized gains	1.3	—	—
Purchases	3.9	15.6	10.6
Sales	(0.1)	—	—
Settlements	(11.9)	(12.1)	(11.8)
Acquisition of Integrys	(1.3)	—	—
Net transfers out of level 3	4.7	—	—
Balance at the end of the period	$3.6	$7.0	$3.5

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:

(in millions)	2015 Carrying Amount	Fair Value	2014 Carrying Amount	Fair Value
Preferred stock	$30.4	$27.3	$30.4	$27.1
Long-term debt, including current portion *	$9,221.9	$9,681.0	$4,510.3	$5,126.0

*Long-term debt excludes capital lease obligations.

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NOTE 20—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

		December 31, 2015		December 31, 2014	
(in millions)	Balance Sheet Presentation	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Natural gas	Other current	$2.6	$38.5	$5.0	$11.5
Natural gas	Other long-term	0.5	3.3	—	0.8
Petroleum products	Other current	0.9	3.8	—	—
Petroleum products	Other long-term	0.3	1.1	—	—
FTRs	Other current	3.6	—	7.0	—
Coal	Other current	1.7	6.7	2.7	0.2
Coal	Other long-term	0.3	5.6	0.6	—
	Other current	8.8	49.0	14.7	11.7
	Other long-term	1.1	10.0	0.6	0.8
Total		$9.9	$59.0	$15.3	$12.5

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

	December 31, 2015		December 31, 2014		December 31, 2013	
(in millions)	Volume	Gains (Losses)	Volume	Gains	Volume	Gains (Losses)
Natural gas	86.2 Dth	$(50.5)	40.5 Dth	$7.3	48.6 Dth	$(8.5)
Petroleum products	7.8 gallons	(1.9)	9.2 gallons	0.5	8.6 gallons	0.5
FTRs	27.3 MWh	6.7	26.1 MWh	12.7	25.3 MWh	14.9
Total		$(45.7)		$20.5		$6.9

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

	December 31, 2015		December 31, 2014	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	$9.9	$59.0	$15.3	$12.5
Gross amount not offset on the balance sheet *	(3.0)	(22.5)	(0.4)	(11.5