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, 2014

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.
1-3016	WISCONSIN PUBLIC SERVICE CORPORATION (A Wisconsin Corporation) 700 North Adams Street P. O. Box 19001 Green Bay, WI 54307-9001 800-450-7260	39-0715160

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

None

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

Preferred Stock, Cumulative, $100 par value

5.00% Series	5.08% Series	6.88% Series
5.04% Series	6.76% Series	

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

Yes [ ] No [X]

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. [X]

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 [ ]	Accelerated filer [ ]
Non-accelerated filer [X]	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]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.
None.

Number of shares outstanding of each class of common stock, as of February 25, 2015
Common Stock, $4 par value, 23,896,962 shares. Integrys Energy Group, Inc. is the sole holder of Wisconsin Public Service Corporation Common Stock.

WISCONSIN PUBLIC SERVICE CORPORATION
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2014
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Acronyms Used in this Annual Report on Form 10-K

AFUDC	Allowance for Funds Used During Construction
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
IES	Integrys Energy Services, Inc.
IRS	United States Internal Revenue Service
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Michigan Public Service Commission
N/A	Not Applicable
NYMEX	New York Mercantile Exchange
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WDNR	Wisconsin Department of Natural Resources
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Forward-Looking Statements

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 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot provide assurance that such statements will prove correct.

Forward-looking statements involve a number of risks and uncertainties. Some risks and uncertainties that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2014, and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting us;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiary are subject;
- The risk of disruption from the proposed merger of our parent, Integrys Energy Group, with Wisconsin Energy Corporation making it more difficult to maintain our business and operational relationships;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The impact of unplanned facility outages;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer energy use, customer growth, and our ability to adequately forecast energy use for our customers;
- 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;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our liquidity and financing efforts;
- The ability to retain market-based rate authority;
- The effects, extent, and timing of competition or additional regulation in the markets in which we operate;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our counterparties, affiliates, and customers to meet their obligations;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- Potential business strategies, including acquisitions, which cannot be assured to be completed timely or within budgets;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we and/or Integrys Energy Group file with the SEC.

Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

PART I

ITEM 1. BUSINESS

A. GENERAL

In this report, when we refer to "us," "we," "our," or "ours," we are referring to WPS. The term "utility" refers to our regulated activities, while the term "nonutility" refers to our activities that are not regulated, as well as the activities of our subsidiary. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

We are a Wisconsin corporation and a wholly owned subsidiary of Integrys Energy Group, Inc. We began operations in 1883. We are an electric and natural gas utility company serving an approximate 12,000-square-mile service territory in northeastern Wisconsin and Michigan's Upper Peninsula. Our three reportable segments are electric utility, natural gas utility, and other. In 2014, electric revenues accounted for 72% of our total utility revenues, while natural gas revenues accounted for 28% of our total utility revenues.

For more information about our electric and natural gas utility operations, including financial and geographic information, see Note 24, Segments of Business, and Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Facilities

For information regarding our electric and natural gas utility facilities, see Item 2, Properties. For our plant asset book values, see Note 6, Property, Plant, and Equipment.

Available Information

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, registration statements, and any amendments to these documents are available, free of charge, on Integrys Energy Group's website, www.integrysgroup.com, as soon as reasonably practicable after they are filed with or furnished to the SEC. Reports, statements, and amendments posted on Integrys Energy Group's website do not include access to exhibits and supplemental schedules electronically filed with the reports, statements, or amendments. We are not including the information contained on or available through the Integrys Energy Group website as a part of, or incorporating such information by reference into, this Annual Report on Form 10-K.

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 our reports, registration statements, and other information (including exhibits) filed or furnished electronically with the SEC, at the SEC's website at www.sec.gov.

B. ELECTRIC UTILITY OPERATIONS

Our electric utility operations provide service to approximately 450,000 residential, commercial and industrial, wholesale, and other customers. Our customers are located in northeastern Wisconsin and Michigan's Upper Peninsula. Wholesale electric service is provided to various customers, including municipal utilities, electric cooperatives, energy marketers, other investor-owned utilities, and municipal joint action agencies. In 2014, retail electric revenues accounted for 87.3% of total electric revenues, while wholesale electric revenues accounted for 12.7% of total electric revenues.

Electric Supply

We are a member of MISO, a FERC-approved, independent, nonprofit organization, which operates a financial and physical electric wholesale market in the Midwest. We offer generation and bid customer load into the MISO market. MISO evaluates our and all other market participants' energy offers into, and subsequent withdrawals from, the transmission system to economically and reliably dispatch generation to serve load. MISO settles the participants' offers and bids based on locational marginal prices, which are market-driven values based on the specific time and location of the purchase and/or sale of energy.

Electric Generation and Supply Mix

The sources of our electric utility supply were as follows:

(Millions) Energy Source (*kilowatt-hours*)	2014	2013	2012
Company-owned generation units			
Coal	**7,130.2**	8,723.1	7,390.1
Natural gas, fuel oil, and tire-derived fuel (1)	**1,705.8**	1,539.4	175.9
Wind	**326.1**	309.7	330.6
Hydro	**423.6**	231.0	176.4
Total company-owned generation units	**9,585.7**	10,803.2	8,073.0
Power purchase contracts (2)			
Nuclear (Kewaunee Power Station) (3)	**—**	2,808.3	2,655.5
Hydro	**355.8**	553.8	392.6
Natural gas (Fox Energy Center) (4)	**—**	395.1	2,892.6
Wind	**221.5**	209.1	220.1
Other	**1,506.8**	674.0	1,580.5
Total power purchase contracts	**2,084.1**	4,640.3	7,741.3
Purchased power from MISO	**2,960.3**	600.3	584.7
Total purchased power	**5,044.4**	5,240.6	8,326.0
Opportunity sales			
Sales to MISO	**(286.8)**	(1,591.4)	(1,799.5)
Net sales to other	**(303.7)**	(407.8)	(128.4)
Total opportunity sales	**(590.5)**	(1,999.2)	(1,927.9)
Total electric utility supply	**14,039.6**	14,044.6	14,471.1

(1) Reflects the purchase of Fox Energy Company LLC in March 2013. See Note 3, Acquisition of Fox Energy Center, for more information.

(2) See Note 15, Commitments and Contingencies, for more information on power purchase obligations.

(3) This power purchase contract expired in December 2013.

(4) This power purchase contract was terminated in connection with the purchase of Fox Energy Company LLC in March 2013. See Note 3, Acquisition of Fox Energy Center, for more information.

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. 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 under Module E of its Open Access Transmission and Energy Markets Tariff. MISO has a 14.8% reserve margin requirement from January 1, 2015, through May 31, 2015, and 14.3% for the remainder of 2015. 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 all firm electric demand obligations during 2014. In 2015, we expect to have adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations, including the minimum planning reserve margin requirements.

Fuel Costs

The cost of fuel per generation of one million British thermal units was as follows:

Fuel Type	2014	2013	2012
Coal	**$ 2.53**	$ 2.57	$ 2.52
Natural gas	**5.17**	3.47	3.97
Fuel oil	**21.15**	22.16	26.45

Coal Supply

Coal is the primary fuel source for our electric generation facilities. Our fuel portfolio strategy is to maintain a 35- to 45-day supply of coal at each plant site. The majority of the coal is purchased from Powder River Basin mines located in Wyoming. This low sulfur coal has been our lowest cost coal source of any of the subbituminous coal-producing regions in the United States. Historically, we have purchased coal directly from the producer for our wholly owned plants. We also purchase coal for the jointly owned Weston 4 plant and Dairyland Power Cooperative reimburses us for their share of the coal costs. Wisconsin Power and Light Company purchases coal for the jointly owned Edgewater and Columbia plants and we reimburse them for our share of the coal costs. At December 31, 2014, we had coal transportation contracts in place for 100% of our 2015 coal transportation requirements. See Note 15, Commitments and Contingencies, for more information on coal purchases and coal deliveries under contract.

Regulatory Matters

Our retail electric rates are regulated by the PSCW and the MPSC. The FERC regulates our wholesale electric rates. We must also comply with mandatory electric system reliability standards developed by the North American Electric Reliability Corporation (NERC), the electric reliability organization certified by the FERC. The Midwest Reliability Organization is responsible for the enforcement of NERC's standards for us.

The PSCW sets rates through its ratemaking process, which is based on recovery of operating costs and a return on invested capital. One of the cost recovery components is fuel and purchased power, which is governed by a fuel window mechanism. The MPSC's ratemaking process is similar to the PSCW's, with the exception of fuel and purchased power costs, which are recovered on a one-for-one basis. See Note 1(e), Revenues and Customer Receivables, for more information. We charge formula-based rates, as approved by the FERC, for the sale of electricity to our wholesale customers.

See Note 22, Regulatory Environment, for more information regarding our rate cases and decoupling mechanisms.

Hydroelectric Licenses

We and WRPC (a company in which we have 50% ownership) have long-term licenses from the FERC for our hydroelectric facilities.

Other Matters

Seasonality

Our electric utility sales are generally higher during the summer months due to the air conditioning requirements of our customers.

Competition

The retail electric utility market in Wisconsin is regulated by the PSCW. Retail electric customers currently do not have the ability to choose their electric supplier. However, utilities still face competition from other energy sources, such as self-generation by large industrial customers and alternative energy sources. In addition, utilities work to attract new customers into their service territories in order to increase sales. As a result, there is competition among utilities to keep energy rates low. Wisconsin utilities have continued to refine regulated tariffs in order to better match the cost of electricity to each class of customer by reducing or eliminating rate subsidies among different ratepayer classes.

Michigan electric energy markets are open to competition, subject to certain limitations. Since 2012, alternate energy suppliers entered our service territory in the Upper Peninsula of Michigan, creating an active competitive market resulting in some lost load.

C. NATURAL GAS UTILITY OPERATIONS

Our natural gas utility operations provide service to approximately 326,000 residential, commercial and industrial, transportation, and other customers. Our customers are located in northeastern Wisconsin and Michigan's Upper Peninsula.

Natural Gas Supply

We manage a portfolio 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 index price purchases, contracted storage, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

For more information on our natural gas utility supply and transportation contracts, see Note 15, Commitments and Contingencies.

We contract with various underground storage service providers for 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, thus providing a hedge against supply cost volatility. We further reduce our supply cost volatility through the use of financial instruments such as commodity futures and options as part of our hedging programs.

We had adequate capacity to meet all firm natural gas demand obligations during 2014 and expect to have adequate capacity to meet all firm demand obligations during 2015. Our forecasted design peak-day throughput is 651 thousands of dekatherms (MDth) for the 2014 through 2015 heating season.

The sources of our deliveries to customers (including transportation customers) were as follows:

(MDth)	2014	2013	2012
Natural gas purchases	**51,427**	45,071	37,390
Natural gas purchases for electric generation	**1,655**	2,246	2,215
Customer-owned natural gas received	**35,803**	35,301	32,690
Underground storage, net	**(1,939)**	1,626	675
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted-for natural gas	**(1,429)**	(1,986)	(1,997)
Total	**85,517**	82,258	70,973

Regulatory Matters

Our natural gas retail rates are regulated by the PSCW and MPSC. These commissions have general supervisory and regulatory powers over public utilities in Wisconsin and Michigan, respectively.

Sales are made and services are rendered pursuant to rate schedules on file with the PSCW and MPSC. These rate schedules contain various service classifications, which largely reflect customers' different uses and levels of consumption. We bill customers for the distribution of natural gas as well as for a natural gas charge representing third-party costs for purchasing, transporting, and storing natural gas. This charge also includes gains, losses, and costs incurred under a hedging program, the amount of which is also subject to PSCW and MPSC authority. Prudently incurred natural gas costs are passed through to customers in current rates (sometimes referred to as the "natural gas charge") and, therefore, have no impact on margins. Commissions in both jurisdictions conduct annual proceedings regarding the reconciliation of revenues from the natural gas charge and related natural gas costs.

Almost all of the natural gas we distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services 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 PSCW are responsible for monitoring and enforcing requirements governing our safety compliance program 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 service and grant credit (with applicable deposit requirements) to customers within our service territories. We are generally not allowed to discontinue service during winter moratorium months to residential heating customers who do not pay their bills. The Federal, Wisconsin, and Michigan governments have programs that provide for a limited amount of funding for assistance to our low-income customers.

See Note 22, Regulatory Environment, for information regarding our rate cases and decoupling mechanisms.

Other Matters

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. During 2014, the natural gas utility segment recorded approximately 69% of its revenues in January, February, March, November, and December.

Competition

Although our natural gas retail rates are regulated by the PSCW and MPSC, 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.

We offer natural gas transportation service and 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 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 natural gas utility segment 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.

Working Capital Requirements

The working capital needs of our natural gas utility operations vary significantly over time due to volatility in levels of natural gas inventories and the price of natural gas. Our working capital needs are met by cash generated from operations and short-term debt. The seasonality of natural gas revenues causes the timing of cash collections to be heavily 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.

D. ENVIRONMENTAL MATTERS

See Note 15, Commitments and Contingencies, for more information on our environmental matters.

E. CAPITAL REQUIREMENTS

For information on our capital requirements, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.

F. EMPLOYEES

At December 31, 2014, we had 1,333 employees, of which 1,276 were full-time. Approximately 69% of our total employees were represented by Local 420 of the International Union of Operating Engineers. The current Local 420 collective bargaining agreement expires on October 15, 2016.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors, as well as the other information included or incorporated by reference in this Annual Report on Form 10-K, when making an investment decision.

Risks Related to Our Business

We are subject to government regulation, which may have a negative impact on our business, financial position, and results of operations.

We are subject to comprehensive regulation by several federal and state regulatory agencies and local governmental bodies. 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, construction and operation of facilities, conditions of service, the issuance of securities, and the rates that we can charge customers. We are required to have numerous permits, approvals, and certificates from these agencies to operate our business. Failure to comply with any applicable rules or regulations may lead to penalties or customer refunds, which could have a material adverse impact on our financial results.

Existing statutes and regulations may be revised or reinterpreted by federal and state regulatory agencies, or these agencies may adopt new laws and regulations that apply to us. We are unable to predict the impact on our business and operating results of any such actions by these agencies. However, changes in regulations or the imposition of additional regulations may require us to incur additional expenses or change business operations, which may have an adverse impact on our results of operations.

The rates that we are allowed to charge for retail and wholesale services are the most important factors influencing our business, financial position, results of operations, and liquidity. Rate regulation is premised on providing an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, there is no assurance that regulatory commissions will consider all of our costs to have been prudently incurred. In addition, the regulatory process will not always result in rates that will produce full recovery of such costs or provide for a reasonable return on equity. Certain expense and revenue items are deferred as regulatory assets and liabilities for future recovery or refund to customers, as authorized by regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for prudence and reasonableness. If recovery of costs is not approved or is no longer deemed probable, regulatory assets would be recognized in current period expense and could have a material adverse impact on our financial results.

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

Any future terrorist attack, cyber security attack, and/or act of war affecting our facilities and operations could have an adverse impact on our results of operations, financial condition, and cash flows. The energy industry uses sophisticated information technology systems and network infrastructure, which control an interconnected system of generation, distribution, and transmission systems shared with other third parties. A successful physical or cyber security attack 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 physical and cyber security attacks, including those targeting information systems and electronic control systems used at generating facilities and electric and natural gas transmission and distribution systems, could severely disrupt our operations and result in loss of service to customers. The risk of such attacks may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our business requires the collection and retention of personally identifiable information of our customers, shareholders, and employees, who expect that we will adequately protect such information. A significant theft, loss, or fraudulent use of personally identifiable information may cause our business reputation to be adversely impacted, may lead to potentially large costs to notify and protect the impacted persons, and/or may cause us to become subject to legal claims, fines, or penalties, any of which could adversely impact our results of operations.

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.

We are actively involved with several significant capital projects, which are subject to a number of risks and uncertainties that may adversely affect the cost, timing, and completion of the projects.

Our utility operations are capital intensive and require significant investments in energy generation, delivery, and other projects, including projects for environmental compliance and distribution system improvements. In addition, IBS has various capital projects which are primarily related to the development of software applications used in part to support our utility operations.

Achieving the intended benefits of any large construction project is subject to many uncertainties. These uncertainties include the ability to adhere to established budgets and time frames, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There may also be contractor or supplier performance issues or adverse changes in their creditworthiness and difficulties meeting critical regulatory requirements. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, the 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.

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.

The operation of electric generation and natural gas and electric distribution facilities involves many risks, including the risk of potential breakdown or failure of equipment or processes. Potential breakdown or failure may occur due to storms; catastrophic events (explosions, fires, tornadoes, floods, etc.); aging infrastructure; 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; and performance below expected levels. 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 may require us to incur significant costs by forcing us to operate our higher cost electric generators or purchase replacement power to satisfy our obligations. Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses.

We are obligated to provide safe and reliable service to customers within our service territories. Meeting this commitment requires significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards could adversely affect our operating results through the imposition of penalties and fines or other adverse regulatory outcomes.

Fluctuating commodity prices may impact energy margins and result in changes to liquidity requirements.

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

- Higher working capital costs, 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.

Our operations are subject to various conditions which can result in fluctuations in the number of customers and their energy use.

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

- Fluctuations in general economic conditions and growth within our service areas;
- Weather conditions; and
- Our customers' continued focus on energy efficiency and ability to meet their own energy needs.

We are subject to environmental laws and regulations, compliance with which could be difficult and costly.

We are subject to numerous federal and state environmental laws and regulations that affect many aspects of our operations, including future operations. These laws and regulations relate to air emissions (including greenhouse gas emissions), water quality, wastewater discharges, hazardous materials management, and the generation, transport, and disposal of solid and hazardous wastes. Such laws and regulations require us to implement compliance processes and obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections, and other approvals. Existing laws and regulations may be revised and/or new laws and regulations passed, including, but not limited to, rules addressing greenhouse gases such as carbon dioxide and methane, mercury, sulfur dioxide, and nitrogen oxide emissions, and the management of coal combustion byproducts, including fly ash.

Future regulation may affect the capital expenditures we would make for our generation units or distribution systems, including costs to further limit the greenhouse gas emissions from our operations through control technology. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could affect the availability or cost of fossil fuels. The steps we could be required to take to ensure that our facilities are in compliance with any such laws and regulations could be prohibitively expensive. As a result, certain coal-fired electric generating facilities may become uneconomical to run and could result in early retirement of some of our units or may force us to convert the units 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 could result. This could impair the reliability of the Midwest portion of the grid, especially during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

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. Carbon dioxide is also a byproduct of natural gas consumption. As a result, future legislation to regulate greenhouse gas emissions could increase the price of natural gas, restrict the use of natural gas, adversely affect our ability to operate our natural gas facilities, and/or reduce natural gas demand.

Environmental laws and regulations can also require us to incur expenditures for cleanup costs, damages arising from contaminated properties, and monitoring obligations. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all recoverable costs incurred to date, management's best estimates of future costs for investigation and remediation, and legal expenses, and are net of amounts recovered by or that may be recovered from insurance or other entities. The ultimate costs to remediate these sites could vary from the amounts currently accrued.

There is uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Citizen groups that feel environmental regulations are not being sufficiently enforced by environmental regulatory agencies may also bring citizen enforcement actions against us. Such actions could seek penalties, injunctive relief, and costs of litigation. There is also a risk that private citizens may bring lawsuits to recover environmental damages they believe they have incurred.

Compliance with current and future environmental laws and regulations may result in increased capital, operating, and other costs. Compliance could also impact future results of operations, cash flows, and financial condition if such costs are not recoverable through regulated rates. Noncompliance could result in fines, penalties, and injunctive measures negatively affecting our operations and facilities.

Adverse capital and credit market conditions could negatively affect our ability to meet liquidity needs, access capital, and/or grow or sustain our current business. Cost of capital and disruptions, uncertainty, and/or volatility in the financial markets could adversely impact our results of operations and financial condition.

Having access to the credit and capital markets, at a reasonable cost, is necessary for us to fund our operations and capital requirements. The capital and credit markets provide us with liquidity to operate and grow our business that is not otherwise provided from operating cash flows. Disruptions, uncertainty, and/or volatility in those markets could increase our cost of capital or limit the availability of capital. If we or Integrys Energy Group are unable to access the credit and capital markets on terms that are reasonable, we may have to delay raising capital, issue shorter-term securities, and/or bear an increased cost of capital. This, in turn, could impact our ability to grow or sustain our current business, cause a reduction in earnings, and/or result in a credit rating downgrade.

A reduction in our credit ratings could materially and adversely affect our business, financial position, results of operations, and liquidity.

We cannot be sure that any of our credit ratings will not be lowered by a rating agency if, in the rating agency's judgment, circumstances in the future so warrant. Any downgrade could:

- Require the payment of higher interest rates in future financings and possibly reduce the potential pool of creditors;
- Increase borrowing costs under certain existing credit facilities;
- Limit access to the commercial paper market; and
- Require provision of additional credit assurance, including cash margin calls, to contract counterparties.

Any change in our authority to sell electricity at market-based rates may impact earnings.

The FERC has authorized us to sell electricity in the wholesale market at market prices. We must file an updated market power analysis with the FERC at least every three years to demonstrate we do not possess market power in that region. The FERC retains the authority to modify, revoke, or rescind this market-based rate authority. If the FERC determines that the relevant market is not workably competitive, that we possess market power, that we are not charging just and reasonable rates, or that we have not complied with the rules required in order to maintain market-based rates, the FERC may require us to sell power at a price based upon the costs incurred in producing the power, or otherwise revoke or rescind our authority in that market. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates we may receive, or otherwise by any revocation or rescission of such authority.

Counterparties and customers may not meet their obligations.

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 forced to replace the underlying commitment at then-current market prices or we may be unable to meet all of our customers' natural gas and electric requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, or our results of operations, financial position, or liquidity could otherwise be adversely affected.

We are dependent on coal for much of our electric generating capacity. 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. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be forced to reduce generation at our coal-fired units and replace this lost generation through additional power purchases in the MISO market. There is no guarantee that we would be able to fully recover any increased costs in rates. Our electric generation frequently exceeds our customer load. When this occurs, we generally sell the excess generation into the MISO market. 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.

Our customers may experience financial problems. Financially distressed customers might default on their obligations to us or reduce their future use of our products and services. We cannot assure that such defaults or reductions in use of our products and services will not have a material adverse impact on our business, financial position, results of operations, or cash flows.

Poor investment performance of retirement plan investments and other factors impacting retirement plan costs could unfavorably impact our liquidity and results of operations.

We participate in employee benefit plans that cover substantially all of our employees and retirees. Our cost of providing these benefit plans varies depending upon actual plan experience and assumptions concerning the future. These assumptions include earnings on and/or valuations of 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 required or voluntary contributions to the plans. Depending on the investment performance over time and other factors impacting our costs, we could be required to make larger contributions in the future to fund these plans. These additional funding obligations could have a material adverse impact on our cash flows, financial condition, and/or results of operations. Changes made to the plans may also impact current and future pension and other postretirement benefit costs.

Risk Related to the Proposed Merger of Integrys Energy Group with Wisconsin Energy Corporation (Wisconsin Energy)

The proposed merger of our parent company, Integrys Energy Group, and Wisconsin Energy could negatively impact our financial results.

Uncertainty about the effect of the merger on employees, suppliers, and customers may have an adverse effect on us. We are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plan. Uncertainty about their future roles with the combined company may impair our ability to attract, retain, and motivate key personnel until the merger is completed and for a period of time thereafter. Uncertainties could also cause customers, suppliers, and others who deal with us to seek changes to our existing business relationships.

The pursuit of the merger and the preparation for the integration of our parent and Wisconsin Energy may place a significant burden on management and internal resources. Any significant diversion of management's attention away from our operations or the pursuit of other opportunities that could have been beneficial to us could affect our financial results.

There may also be adverse consequences to our business and our relations with governmental agencies arising out of the efforts to obtain regulatory approvals for the merger if such efforts are unsuccessful. In addition, we can provide no assurance that required regulatory authorizations, approvals, or consents will not contain terms, conditions, or restrictions that could be detrimental to us.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2014:

Type	Name	Location	Primary Fuel	Rated Capacity (Megawatts) [1]
Steam	Columbia Units 1 and 2	Portage, Wisconsin	Coal	**353.0** [2]
	Edgewater Unit 4	Sheboygan, Wisconsin	Coal	**93.8** [2]
	Pulliam (4 units)	Green Bay, Wisconsin	Coal	**325.4** [3]
	Weston Units 1, 2, and 3	Marathon County, Wisconsin	Coal	**450.6** [3]
	Weston Unit 4	Marathon County, Wisconsin	Coal	**372.8** [2]
Total Steam				**1,595.6**
Combustion Turbine and Diesel	Fox Energy Center	Kaukauna, Wisconsin	Natural Gas	**551.6**
	De Pere Energy Center	De Pere, Wisconsin	Natural Gas	**159.4**
	Juneau #31	Adams County, Wisconsin	Distillate Fuel Oil	**6.2** [4]
	Pulliam #31	Green Bay, Wisconsin	Natural Gas	**79.9**
	West Marinette #31	Marinette, Wisconsin	Natural Gas	**38.4**
	West Marinette #32	Marinette, Wisconsin	Natural Gas	**38.4**
	West Marinette #33	Marinette, Wisconsin	Natural Gas	**73.6**
	Weston #31	Marathon County, Wisconsin	Natural Gas	**12.3**
	Weston #32	Marathon County, Wisconsin	Natural Gas	**21.9**
Total Combustion Turbine and Diesel				**981.7**
Hydroelectric	Various	Wisconsin and Michigan	Hydro	**60.8** [5]
Wind	Lincoln	Wisconsin	Wind	**0.9**
	Crane Creek	Iowa	Wind	**21.0**
Total Wind				**21.9**
Total System				**2,660.0**

(1) Based on capacity ratings for summer 2015, 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.

(2) We jointly own these facilities with various other utilities. The capacity indicated for each of these units is equal to our portion of total plant capacity based on our percent of ownership.

- Wisconsin Power and Light Company operates the Columbia and Edgewater units. We hold a 31.8% ownership interest in these facilities.
- We operate the Weston 4 facility and hold a 70% ownership interest in this facility. Dairyland Power Cooperative holds the remaining 30%.

(3) In connection with the Consent Decree with the EPA, the Weston 1, Pulliam 5, and Pulliam 6 generating units will be retired early, in June 2015. These units have an aggregate generating capacity of 166.9 megawatts (based on summer 2015 capacity ratings). Weston 2 is also part of this EPA Consent Decree; however, it will not be retired but rather will operate on natural gas starting in June 2015. See Note 15, Commitments and Contingencies, for more information regarding the Consent Decree.

(4) WRPC owns and operates the Juneau unit. We hold a 50% ownership interest in WRPC and are entitled to 50% of the total capacity from the Juneau unit.

(5) WRPC owns and operates the Castle Rock and Petenwell units. We hold a 50% ownership interest in WRPC and are entitled to 50% of the total capacity at Castle Rock and Petenwell. Our share of capacity for Castle Rock is 8.7 megawatts and our share of capacity for Petenwell is 10.5 megawatts.

As of December 31, 2014, our electric utility owned approximately 21,900 miles of electric distribution lines located in Michigan and Wisconsin and 124 electric distribution substations.

Natural Gas Facilities

At December 31, 2014, our natural gas properties were located in northeastern Wisconsin and an adjacent portion of Michigan's Upper Peninsula and consisted of the following:

- Approximately 7,800 miles of natural gas distribution mains,
- Approximately 250 miles of natural gas transmission mains,
- Approximately 303,000 natural gas lateral services, and
- 86 natural gas distribution and transmission gate stations.

General

Substantially all of our utility plant is subject to a first mortgage lien.

ITEM 3. LEGAL PROCEEDINGS

See Note 15, Commitments and Contingencies, for more information on material legal proceedings and matters related to us and our subsidiary.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Integrys Energy Group is the sole holder of our common stock; therefore, there is no established public trading market for our common stock. We made no purchases of equity securities during the fourth quarter of 2014. See Note 18, Common Equity, for more information on dividends paid and dividend restrictions.

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN PUBLIC SERVICE CORPORATION
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 (Millions, except weather information)	2014	2013	2012	2011	2010
Operating revenues	**$ 1,682.3**	$ 1,579.3	$ 1,499.2	$ 1,563.1	$ 1,589.0
Net income attributed to common shareholder	**137.6**	134.8	131.7	122.8	131.9
Total assets	**4,278.7**	3,961.3 [1]	3,521.9	3,427.5	3,386.0
Long-term debt (excluding current portion)	**1,052.4**	1,180.8	731.6	579.2	729.7
Weather information [2]					
Cooling degree days	**333**	529	789	603	616
Cooling degree days as a percent of normal	**65.3%**	105.2%	166.1%	125.6%	130.8%
Heating degree days	**8,564**	8,051	6,356	7,524	7,080
Heating degree days as a percent of normal	**114.9%**	108.0%	84.2%	100.1%	94.2%

(1) Includes the impact of the acquisition of the Fox Energy Center in March 2013. See Note 3, Acquisition of Fox Energy Center, for more information.

(2) Normal heating and cooling degree days are based on a 20-year average of monthly temperatures from the Green Bay Weather Station. Daily degree days are calculated by subtracting the 24-hour average daily temperature from 65° Fahrenheit. Heating degree days result if temperatures are less than 65° Fahrenheit and cooling degrees result if temperatures are more than 65° Fahrenheit.

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

INTRODUCTION

We are an electric and natural gas utility and a wholly owned subsidiary of Integrys Energy Group, Inc. We derive revenues primarily from the distribution and sale of electricity and natural gas to retail customers. We also provide wholesale electric service to numerous utilities and cooperatives for resale.

Strategic Overview

Our goal is to create long-term value for Integrys Energy Group's shareholders and our customers through growth, operational excellence, customer focus, risk management, and the continued emphasis on safe, reliable, competitively priced, and environmentally sound energy services.

The essential components of our business strategy are:

Providing Safe, Reliable, Competitively Priced, and Environmentally Sound Energy and Related Services – Our mission is the same as Integrys Energy Group's: to provide customers with the best value in energy and related services. We strive to effectively operate a mixed portfolio of generation assets and prudently invest in new generation and distribution assets, while maintaining or exceeding environmental standards. We continue to construct and/or upgrade equipment through planned capital projects each year to provide a safe, reliable, and value-priced service for our customers. We believe the following projects have helped, or will help, maintain and grow our utility base and meet our customers' needs:

- Our proposed new natural gas-fueled electric generating unit to be built at the site of the Fox Energy Center in Wisconsin,
- Our continued investment in environmental projects to improve air quality and meet or exceed the requirements set by environmental regulators, and
- The System Modernization and Reliability Project to underground and upgrade certain electric distribution facilities in northern Wisconsin.

For more detailed information on our capital expenditure program, see Liquidity and Capital Resources – Capital Requirements.

Integrating Resources to Provide Operational Excellence and Customer Focus – We are committed to integrating resources and finding the best and most efficient processes while meeting all applicable legal and regulatory requirements. We strive to provide the best value to our customers and Integrys Energy Group's shareholders by embracing constructive change, leveraging capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations. "Operational Excellence" initiatives have been implemented to reduce costs and encourage top performance in the areas of project management, process improvement, contract administration, and compliance.

Placing Strong Emphasis on Risk Management – Our risk management strategy includes the management of market, credit, liquidity, and operational risks through the normal course of business. Forward purchases of electric capacity, energy, natural gas, and other commodities, and the use of derivative financial instruments, including commodity options, provide tools to reduce the risk associated with price movement in a volatile energy market. We manage our risk profile related to these instruments consistent with Integrys Energy Group's risk management policy for regulated affiliates, which is approved by the Integrys Energy Group Board of Directors. The Integrys Energy Group Corporate Risk Management Group, which reports through Integrys Energy Group's Chief Financial Officer, provides corporate oversight. We also use formula-based market tariffs to manage risk in the wholesale market.

RESULTS OF OPERATIONS

Earnings Summary

(Millions)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Electric utility operations	**$ 104.7**	$ 102.3	$ 99.1	2.3 %	3.2 %
Natural gas utility operations	**25.7**	25.0	24.9	2.8 %	0.4 %
Other operations	**7.2**	7.5	7.7	(4.0)%	(2.6)%
Net income attributed to common shareholder	**$ 137.6**	$ 134.8	$ 131.7	2.1 %	2.4 %

2014 Compared with 2013

The $2.8 million increase in our earnings was driven by:

- An approximate $18 million net after-tax increase in margins related to our 2014 PSCW electric and natural gas rate orders effective January 1, 2014.

- An approximate $10 million after-tax increase in natural gas utility margins due to variances in sales volumes, net of decoupling. The increase was driven by colder than normal weather in 2014 and higher weather-normalized sales volumes. Our decoupling mechanism was terminated effective January 1, 2014.

- An approximate $6 million after-tax increase in electric wholesale margins driven by higher prices.

These increases were partially offset by:

- A $20.0 million after-tax increase in electric and natural gas utility operating expenses, driven by an increase in maintenance expense and higher depreciation and amortization expense.

- A $9.7 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.

2013 Compared with 2012

The $3.1 million increase in our earnings was driven by an approximate $11 million after-tax increase in electric margins due to the 2013 PSCW rate order. This increase was partially offset by a $10.9 million after-tax increase in electric transmission expense and maintenance expense, excluding the newly acquired Fox Energy Center. The increase in maintenance expense was driven primarily by a plant outage at Weston 3.

Electric Utility Segment Operations

	Year Ended December 31			Change in 2014	Change in 2013
(Millions, except degree days)	**2014**	**2013**	**2012**	**Over 2013**	**Over 2012**
Revenues	**$ 1,222.4**	$ 1,241.8	$ 1,212.0	(1.6)%	2.5 %
Fuel and purchased power costs	**460.0**	519.8	545.4	(11.5)%	(4.7)%
Margins	**762.4**	722.0	666.6	5.6 %	8.3 %
Operating and maintenance expense	**417.7**	398.6	367.2	4.8 %	8.6 %
Depreciation and amortization expense	**97.4**	90.5	81.1	7.6 %	11.6 %
Taxes other than income taxes	**41.9**	43.4	42.3	(3.5)%	2.6 %
Operating income	**205.4**	189.5	176.0	8.4 %	7.7 %
Miscellaneous income	**11.1**	9.9	2.6	12.1 %	280.8 %
Interest expense	**45.1**	33.0	32.4	36.7 %	1.9 %
Other expense	**(34.0)**	(23.1)	(29.8)	47.2 %	(22.5)%
Income before taxes	**$ 171.4**	$ 166.4	$ 146.2	3.0 %	13.8 %
Sales in kilowatt-hours					
Residential	**2,862.3**	2,862.3	2,844.0	— %	0.6 %
Commercial and industrial	**7,926.1**	7,930.9	8,004.8	(0.1)%	(0.9)%
Wholesale	**3,324.0**	4,761.7	5,049.9	(30.2)%	(5.7)%
Other	**32.2**	32.6	32.8	(1.2)%	(0.6)%
Total sales in kilowatt-hours	**14,144.6**	15,587.5	15,931.5	(9.3)%	(2.2)%
Weather					
Actual heating degree days	**8,564**	8,051	6,356	6.4 %	26.7 %
Normal heating degree days	**7,454**	7,452	7,548	— %	(1.3)%
Actual cooling degree days	**333**	529	789	(37.1)%	(33.0)%
Normal cooling degree days	**510**	503	475	1.4 %	5.9 %

Electric utility margins are defined as electric utility operating revenues less fuel and purchased power costs. Management believes that electric utility margins provide a more meaningful basis for evaluating electric utility operations than electric utility operating revenues. To the extent changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in operating revenues.

2014 Compared with 2013

Margins

Electric utility segment margins increased $40.4 million, driven by:

- An approximate $35 million increase in margins related to our PSCW rate order, effective January 1, 2014. Although the PSCW approved an electric rate decrease, the rate decrease was driven by 2013 fuel cost over-collections and 2012 decoupling over-collections that were being refunded to customers in 2014 and had no impact on margins. See Note 22, Regulatory Environment, for more information.

    - Margins increased approximately $41 million as a result of the PSCW rate order, primarily driven by an increase in electric rate base from owning and operating the Fox Energy Center, which was included in rates beginning in 2014. In 2013, customer rates only included recovery of estimated purchased power costs from the Fox Energy Center.

    - Margins were positively impacted by approximately $5 million mainly due to lower fly ash disposal costs in 2014. These costs are not included in the fuel rule recovery mechanism.

    - Margins decreased by approximately $11 million related to fuel and purchased power cost under-collections in 2014, compared with over-collections in 2013. Under the fuel rule, we can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

- An approximate $9 million increase in wholesale margins driven by higher prices. Wholesale prices increased due to higher generation costs as well as an increase in electric rate base, resulting from the purchase of the Fox Energy Center in 2013 and the installation of environmental projects at the Columbia plant in 2014. Wholesale customers proportionally shared in these price increases through formula rates.

- A partially offsetting decrease in margins of approximately $3 million related to sales volume variances. The decrease in margins was primarily driven by lower sales volumes from both our large commercial and industrial customers as well as our residential customers. The decrease in these sales volumes was driven by lower use per customer in 2014. This decrease was partially offset by the impact of the termination of our decoupling mechanism, effective January 1, 2014. See Note 22, Regulatory Environment, for more information. Our decoupling mechanism did not cover large commercial and industrial customers.

Operating Income

Operating income at the electric utility segment increased $15.9 million. The increase was driven by the $40.4 million increase in margins discussed above, partially offset by a $24.5 million increase in operating expenses.

The increase in operating expenses was driven by:

- A $15.1 million increase in maintenance expense, primarily due to planned major outages in 2014 at the Pulliam plant, Fox Energy Center, and Weston 4, as well as maintenance at certain other generation plants. These increases were partially offset by the year-over-year impact of maintenance expenses associated with the Weston 3 planned major outage in 2013.

- A $6.9 million increase in depreciation and amortization expense, mainly due to the acquisition of the Fox Energy Center at the end of the first quarter of 2013. In addition, we completed the installation of scrubbers at the Columbia plant in April 2014.

- A $6.0 million increase in costs associated with the acquisition and operation of the Fox Energy Center. The majority of this increase relates to the amortization of a regulatory asset related to the fee paid for the early termination of the Fox Energy Center power purchase agreement. Recovery of the amortization was included in the new rates.

- A $5.4 million increase in electric transmission expense.

- A $2.8 million increase in amortization of previously deferred production tax credits related to the Crane Creek wind project.

These increases were partially offset by:

- A $6.6 million decrease due to the year-over-year impact of the 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The 2013 PSCW rate order did not reflect this purchase or the related termination of a power purchase agreement. However, we did receive PSCW approval to defer ownership costs above or below our power purchase agreement expenses in 2013.

- A $5.2 million net decrease in employee benefit costs, including the impact of the prior year deferral of some of these costs. Employee benefit costs other than stock-based compensation (discussed below) decreased $24.0 million in 2014. This decrease was partially driven by the continued funding of our pension plan and higher discount rates assumed in 2014 for both our pension and postretirement plans. The remeasurement of certain other postretirement benefit plans also contributed to the overall decrease in employee benefit costs. See Note 16, Employee Benefit Plans, for more information. This decrease was partially offset by:

- Higher stock-based compensation expense of $4.3 million, which was primarily driven by an increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in Integrys Energy Group's stock price.

- The year-over-year impact of a deferral of certain increases in employee benefit costs in 2013, recorded in accordance with our PSCW rate order, and the related amortization in 2014. Together, these changes increased employee benefit costs by $14.5 million.

Other Expense

Other expense increased $10.9 million. The primary driver was a $14.1 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt in 2014. An increase in AFUDC of $1.8 million partially offset this increase. AFUDC was higher largely due to the construction of the ReACT™ emission control technology at the Weston 3 plant and the System Modernization and Reliability Project, partially offset by environmental compliance projects at the Columbia plant completed earlier in 2014.

2013 Compared with 2012

Margins

Electric utility segment margins increased $55.4 million, driven by:

- An approximate $32 million increase in margins related to lower fuel and purchased power costs. The decline in purchased power costs was driven by the termination of a power purchase agreement in connection with the acquisition of Fox Energy Company LLC. Our retail margins were positively impacted by the reduction in the capacity charges under the agreement, which are not included in our fuel and purchased power cost recovery mechanism. This had no impact on net income as the net difference between the lower purchased power costs and the costs of owning the plant are deferred for recovery or refund in a future PSCW retail rate case (the net difference is reflected in operating expenses below). Wholesale margins also increased as a result of the acquisition. Although purchased power costs decreased, wholesale revenues subsequent to the purchase of Fox Energy Company LLC include higher operating costs resulting from the ownership of the plant (see below).

- An approximate $19 million increase in margins due to a retail electric rate increase, effective January 1, 2013. See Note 22, Regulatory Environment, for more information on our 2013 PSCW rate order.

- An approximate $8 million net increase in margins from residential and commercial and industrial customers due to variances related to sales volumes, including the impact of decoupling. The year-over-year impact of decoupling does not directly correlate with the year-over-year impact of the change in sales volumes as our decoupling mechanism was changed in 2013. See Note 22, Regulatory Environment, for more information.

Partially offsetting these increases was an approximate $4 million decrease in wholesale margins driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one large customer.

Operating Income

Operating income at the electric utility segment increased $13.5 million. The increase was driven by the $55.4 million increase in margins discussed above, partially offset by a $41.9 million increase in operating expenses. The increase in operating expenses was driven by:

- A $15.2 million increase in maintenance expense due to a greater number of planned outages for certain of our generation plants in 2013, driven primarily by an outage at Weston 3. Also included in this amount is maintenance expense associated with the recently acquired Fox Energy Center.

- A $9.4 million increase in depreciation and amortization expense mainly due to the acquisition of the Fox Energy Center, partially offset by a reduction in the depreciable basis of our Crane Creek wind project. The reduction was the result of our election to claim a Section 1603 Grant for the project in lieu of production tax credits.

- A $9.1 million increase in electric transmission expense.

- A $5.6 million increase due to our deferral of the net difference between actual and rate case-approved costs resulting from the purchase of Fox Energy Company LLC. Our 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, we did receive approval from the PSCW to defer ownership costs above or below our power purchase agreement expenses for recovery or refund in a future rate case.

- A $5.1 million increase in various costs associated with the acquisition and operation of the Fox Energy Center.

- A $3.3 million increase in customer assistance expense, driven by the year-over-year change in the amortization of amounts recoverable from or refundable to customers related to energy efficiency.

In addition, a $4.1 million increase in employee benefit expenses was more than offset by the $7.3 million positive impact of the deferral of certain components of pension and other employee benefit costs that will be recovered in a future rate proceeding as a result of our 2013 PSCW rate order. The increase in employee benefit expenses was driven by a lower discount rate in 2013, which increased both the pension and other postretirement benefit expenses.

Other Expense

Other expense decreased $6.7 million, primarily driven by an increase in AFUDC due to environmental compliance projects at the Columbia plant. The increase in AFUDC was partially offset by an increase in interest expense driven by the financing of the purchase of Fox Energy Company LLC.

Natural Gas Utility Segment Operations

	Year Ended December 31			Change in 2014 Over 2013	Change in 2013 Over 2012
(Millions, except heating degree days)	**2014**	**2013**	**2012**		
Revenues	**$ 472.3**	$ 348.4	$ 296.4	35.6 %	17.5 %
Natural gas purchased for resale	**326.9**	214.5	167.0	52.4 %	28.4 %
Margins	**145.4**	133.9	129.4	8.6 %	3.5 %
Operating and maintenance expense	**71.8**	63.6	61.5	12.9 %	3.4 %
Depreciation and amortization expense	**16.2**	15.6	15.0	3.8 %	4.0 %
Taxes other than income taxes	**4.8**	4.7	5.1	2.1 %	(7.8)%
Operating income	**52.6**	50.0	47.8	5.2 %	4.6 %
Miscellaneous income	**0.4**	0.2	0.1	100.0 %	100.0 %
Interest expense	**10.2**	8.5	7.9	20.0 %	7.6 %
Other expense	**(9.8)**	(8.3)	(7.8)	18.1 %	6.4 %
Income before taxes	**$ 42.8**	$ 41.7	$ 40.0	2.6 %	4.3 %
Retail throughput in therms					
Residential	**284.7**	264.3	208.2	7.7 %	26.9 %
Commercial and industrial	**175.8**	165.3	120.6	6.4 %	37.1 %
Other	**27.3**	32.6	46.9	(16.3)%	(30.5)%
Total retail throughput in therms	**487.8**	462.2	375.7	5.5 %	23.0 %
Transport throughput in therms					
Commercial and industrial	**367.4**	360.4	334.0	1.9 %	7.9 %
Total throughput in therms	**855.2**	822.6	709.7	4.0 %	15.9 %
Weather					
Actual heating degree days	**8,564**	8,051	6,356	6.4 %	26.7 %
Normal heating degree days	**7,454**	7,452	7,548	— %	(1.3)%

Natural gas utility margins are defined as natural gas utility operating revenues less the cost of natural gas purchased for resale. 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. There were approximately 44% and 4% increases in the average per-unit cost of natural gas sold during 2014 and 2013, respectively, which had no impact on margins.

2014 Compared with 2013

Margins

Natural gas utility segment margins increased $11.5 million.

- The combined effect of the change in weather year over year, the impact of higher weather-normalized volumes, and the impact of our decoupling mechanism increased margins approximately $17 million. In 2014, our margins were positively impacted by colder than normal weather as we no longer had a decoupling mechanism in place, effective January 1, 2014. Higher use per customer and an increase in customers also contributed to the increase in margins in 2014.

- Margins were negatively impacted by approximately $5 million related to our rate order, effective January 1, 2014. Although the PSCW approved a net rate increase, it was driven by the recovery of the 2012 decoupling under-collections to be recovered from customers in 2014, which has no impact on margins. See Note 22, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment increased $2.6 million. This increase was driven by the $11.5 million increase in margins discussed above, partially offset by an $8.9 million increase in operating expenses.

The increase in operating expenses was primarily due to:

- A $3.1 million increase in natural gas distribution costs, driven in part by safety inspections performed during 2014. Additional meter maintenance and higher labor costs related to wage increases also contributed to the increase in costs.

- A $1.4 million increase in bad debt expense, driven by higher natural gas costs in 2014 and an increase in sales volumes.

- A $1.4 million increase driven by higher information technology costs. New servers and software for natural gas management and work asset management systems were placed in service during the third quarter of 2013, resulting in higher asset usage charges from IBS. Also, in 2014, several information technology projects and upgrades were performed, and additional information technology services were provided by IBS.

- A $1.3 million increase driven by higher amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites.

- A $0.7 million net increase in employee benefit costs, driven by:

    - A $4.3 million increase related to the negative year-over-year impact of the deferral of employee benefit costs in 2013 and the related amortization in 2014. In 2013, we deferred certain increases in pension and other employee benefit costs as a result of our 2013 rate order with the PSCW. We began amortizing this regulatory asset in 2014.

    - A $1.8 million increase in stock-based compensation expense, primarily due to the year-over-year increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in Integrys Energy Group's stock price.

    - These increases were partially offset by a $5.3 million decrease in other employee benefit costs, driven in part by higher discount rates assumed in 2014. The remeasurement of certain postretirement benefit plans in the first quarter of 2014 also contributed to the decrease. See Note 16, Employee Benefit Plans, for more information on this remeasurement.

- A $0.6 million increase in depreciation and amortization expense, driven in part by additional investment in gas mains.

These increases in operating expenses were partially offset by a $2.1 million decrease in customer assistance expense, primarily driven by a reduction in costs for energy efficiency programs.

2013 Compared with 2012

Margins

Natural gas utility segment margins increased $4.5 million. Margins increased $7 million due to a 15.9% increase in volumes sold in 2013, net of the impact of decoupling, which was driven by the change in weather year over year. In 2012, our margins were negatively impacted by unusually warm weather. In 2013, our margins were positively impacted by colder than normal weather. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanism. Higher use per customer and an increase in customers also contributed to the increase in margins in 2013. The increase in margins was partially offset by an approximate $3 million decrease related to our rate order effective January 1, 2013. See Note 22, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment increased $2.2 million. This increase was primarily driven by the $4.5 million increase in margins discussed above, partially offset by a $2.3 million increase in operating expenses. The increase in operating expenses was driven by $2.2 million of higher amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites. In 2013, we also deferred $2.1 million of certain increases in our pension and other employee benefit costs that will be recovered in a future rate proceeding as a result of our 2013 rate order.

Other Segment Operations

(Millions)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Operating income	**$ 0.4**	$ 0.5	$ 0.4	(20.0)%	25.0%
Other income	**10.8**	11.2	10.8	(3.6)%	3.7%
Income before taxes	**$ 11.2**	$ 11.7	$ 11.2	(4.3)%	4.5%

2014 Compared with 2013

There was no material change in income before taxes for other segment operations.

2013 Compared with 2012

There was no material change in income before taxes for other segment operations.

Provision for Income Taxes

	Year Ended December 31 2014	2013	2012
Effective Tax Rate	**37.6%**	37.3%	31.7%

2014 Compared with 2013

There was no material change in our effective tax rate period over period.

2013 Compared with 2012

Our effective tax rate increased in 2013. In the fourth quarter of 2012, we elected to claim and subsequently received a Section 1603 Grant for our Crane Creek wind project in lieu of production tax credits (PTCs). As a result, we no longer claim wind PTCs on any of our qualifying facilities. In 2012, we also decreased our provision for income taxes by $5.9 million as a result of our 2013 rate case settlement agreement. We recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. See Note 22, Regulatory Environment, for more information.

For information on changes in the deferred income tax balances, see Note 14, Income Taxes.

LIQUIDITY AND CAPITAL RESOURCES

We believe we have adequate resources to fund ongoing operations and future capital expenditures. These resources include cash balances, liquid assets, operating cash flows, access to debt capital markets, and available borrowing capacity under existing credit facilities. Our borrowing costs can be impacted by short-term and long-term debt ratings assigned by independent credit rating agencies, as well as the market rates for interest. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside of our control.

Operating Cash Flows

2014 Compared with 2013

During 2014, net cash provided by operating activities was $263.5 million, compared with $273.1 million during 2013. The $9.6 million decrease in net cash provided by operating activities was driven by:

- A $79.4 million decrease in cash due to higher costs of natural gas, fuel, and purchased power in 2014. Additional cash was used in 2014 due to higher energy prices and the colder weather.

- A $21.1 million decrease in cash received from income taxes. The decrease in cash received was primarily related to quarterly income tax estimated payments, a federal income tax extension payment made in 2014, and an additional payment upon filing the 2013 tax return. A federal income tax refund received in the first quarter of 2014 for an amended return partially offset these income tax payments.

- A $12.9 million increase in cash paid for interest, primarily driven by higher average outstanding long-term debt in 2014.

- A $13.3 million decrease in cash due to increased operating and maintenance costs in 2014. The increase in operating and maintenance costs was driven by higher electric utility maintenance from planned major outages and other higher costs associated with owning and operating the Fox Energy Center beginning in March 2013.

- A $9.0 million decrease in cash from various deferrals, primarily for system support resource costs, precertification costs for a potential new natural gas combined cycle generating unit, and the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center.

- A $6.0 million increase in contributions to pension and other postretirement benefit plans.

- A $5.0 million decrease in cash driven by higher collateral requirements in 2014 compared with 2013. Collateral requirements are based on forward natural gas and electricity prices and forward positions with counterparties.

- A $3.9 million decrease in cash from insurance recoveries received related to environmental remediation of manufactured gas plant sites.

- A $3.4 million increase in cash used for environmental remediation activities.

These decreases in cash were partially offset by:

- An $91.6 million increase in cash collections from customers, mainly due to rate increases, higher commodity prices, an increase in electric wholesale revenues, and the colder weather in 2014. Included in the electric rate increase was the impact of the increase in rate base related to owning and operating the Fox Energy Center.

- The positive year-over-year impact of a $50.0 million payment in 2013 for the early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

- A $5.9 million increase in cash from customer prepayments and credit balances. In 2013, cash received in relation to amounts billed was lower because customer prepayments had grown during an unusually warm 2012.

2013 Compared with 2012

During 2013, net cash provided by operating activities was $273.1 million, compared with $223.3 million during 2012. The $49.8 million increase in net cash provided by operating activities was driven by:

- A $78.5 million decrease in contributions to pension and other postretirement benefit plans.

- A $30.2 million increase in cash received from income taxes, primarily driven by cash settlements received in 2013 due to the filing of the 2012 tax return.

- A $22.6 million year-over-year positive impact from the repayment of related party payables in 2012. Amounts previously paid to us for the unfunded nonqualified retirement plan were returned to related parties.

These increases were partially offset by:

- A $50.0 million payment in 2013 for the early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

- A $22.1 million increase in cash used to purchase natural gas that was injected into storage. The increase was driven by higher natural gas prices in 2013.

- A $6.1 million decrease in cash related to customer prepayments and credit balances due to higher natural gas prices and higher sales volumes in 2013.

Investing Cash Flows

2014 Compared with 2013

During 2014, net cash used for investing activities was $321.1 million, compared with $556.6 million during 2013. The $235.5 million decrease in net cash used for investing activities was primarily due to $391.6 million of cash used in 2013 to purchase Fox Energy Company LLC. See Note 3, Acquisition of Fox Energy Center, for more information regarding this purchase. Partially offsetting the decrease in net cash used was the year-over-year negative impact of the receipt of a $69.0 million Section 1603 Grant for the Crane Creek wind project in 2013 and an $87.5 million increase in cash used for other capital expenditures (discussed below).

2013 Compared with 2012

During 2013, net cash used for investing activities was $556.6 million, compared with $172.2 million during 2012. The $384.4 million increase in net cash used for investing activities was primarily due to $391.6 million of cash used in 2013 to purchase Fox Energy Company LLC. See Note 3, Acquisition of Fox Energy Center, for more information regarding this purchase. Also contributing to the increase was a $62.1 million increase in cash used to fund other capital expenditures (discussed below). These increases in net cash used were partially offset by the receipt of a $69.0 million Section 1603 Grant for the Crane Creek wind project in 2013.

Capital Expenditures

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

Reportable Segment *(millions)*	**2014**	**2013**	**2012**	**Change in 2014 Over 2013**	**Change in 2013 Over 2012**
Electric utility	**$ 279.3**	$ 595.5	$ 149.4	$ (316.2)	$ 446.1
Natural gas utility	**49.8**	37.7	30.1	12.1	7.6
WPS consolidated	**$ 329.1**	$ 633.2	$ 179.5	$ (304.1)	$ 453.7

2014 Compared with 2013

The decrease in capital expenditures at the electric utility segment was primarily due to our purchase of Fox Energy Company LLC in 2013. Capital expenditures related to environmental compliance projects at the Columbia plant also decreased in 2014. Increased expenditures in 2014 related to the ReACT™ project at Weston 3 and the System Modernization and Reliability Project partially offset the decrease.

The increase in capital expenditures at the natural gas utility segment was primarily related to reinforcements of transmission and distribution systems and the expansion of natural gas services to rural areas.

2013 Compared with 2012

The increase in capital expenditures at the electric utility segment was primarily due to our purchase of Fox Energy Company LLC in 2013. Capital expenditures at the electric utility segment also increased related to the ReACT™ project at Weston 3.

Financing Cash Flows

2014 Compared with 2013

During 2014, net cash provided by financing activities was $57.3 million, compared with $282.7 million during 2013. The $225.4 million decrease in net cash provided by financing activities was driven by:

- A $303.0 million net decrease in cash due to a $450.0 million decrease in the issuance of long-term debt, which was partially offset by a $147.0 million decrease in the repayment of long-term debt. The issuance of long-term debt in 2013 was partially used to finance the acquisition of Fox Energy Company LLC.

- A $145.0 million decrease in equity contributions from Integrys Energy Group, which were used to support the acquisition of Fox Energy Company LLC in 2013.

These decreases in cash were partially offset by:

- A $189.3 million year-over-year increase in net cash provided by financing activities due to $119.5 million of net borrowings of commercial paper in 2014, compared with $69.8 million of net repayments of commercial paper in 2013.

- A $35.0 million return of capital to our parent in 2013.

2013 Compared with 2012

During 2013, net cash provided by financing activities was $282.7 million, compared with $50.1 million of net cash used for financing activities during 2012. The $332.8 million year-over-year positive impact from financing activities was driven by:

- A $160.0 million increase in equity contributions from Integrys Energy Group to support the acquisition of Fox Energy Company LLC.

- A $153.0 million increase in cash due to a $150.0 million increase in the issuance of long-term debt and a $3.0 million decrease in the repayment of long-term debt. The issuance of long-term debt in 2013 included replacing the borrowing of $200.0 million under our term credit facility in 2013, among other things. The cash proceeds from the term credit facility were used to partially finance the acquisition of Fox Energy Company LLC.
- A $15.0 million decrease in payments made to our parent for return of capital.
- An $8.5 million increase in net borrowings of commercial paper.

Significant Financing Activities

For information on short-term debt, see Note 11, Short-Term Debt and Lines of Credit.

For information on long-term debt, see Note 12, Long-Term Debt.

Credit Ratings

Our current credit ratings are listed in the table below:

Credit Ratings	Standard & Poor's	Moody's
Issuer credit rating	A-	A1
First mortgage bonds	N/A	Aa2
Senior secured debt	A	Aa2
Preferred stock	BBB	A3
Commercial paper	A-2	P-1

Credit ratings are not recommendations to buy or sell securities. They are subject to change, and each rating should be evaluated independently of any other rating.

On January 31, 2014, Moody's raised the following credit ratings. Our issuer rating was raised to "A1" from "A2," our first mortgage bonds rating was raised to "Aa2" from "Aa3," our senior secured debt rating was raised to "Aa2" from "Aa3," and our preferred stock rating was raised to "A3" from "Baa1." The upgrade in ratings reflects Moody's views of the regulatory provisions in Wisconsin that are consistent with a generally improving regulatory environment for electric and natural gas utilities in the United States.

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2014, including those of our subsidiary:

		Payments Due By Period			
(Millions)	**Total Amounts Committed**	**2015**	**2016 to 2017**	**2018 to 2019**	**Later Years**
Long-term debt principal and interest payments [1]	**$ 2,342.2**	**$ 181.7**	**$ 222.7**	**$ 84.8**	**$ 1,853.0**
Operating lease obligations	**15.8**	**0.5**	**1.6**	**1.0**	**12.7**
Energy and transportation purchase obligations [2]	**1,243.1**	**223.5**	**246.9**	**225.6**	**547.1**
Purchase orders [3]	**465.0**	**418.4**	**44.6**	**2.0**	**—**
Pension and other postretirement funding obligations [4]	**7.7**	**2.7**	**5.0**	**—**	**—**
Total contractual cash obligations	**$ 4,073.8**	**$ 826.8**	**$ 520.8**	**$ 313.4**	**$ 2,412.8**

(1) Represents bonds and notes issued. We record all principal obligations on the balance sheet.

(2) The costs of energy and transportation purchase obligations are expected to be recovered in future customer rates.

(3) Includes obligations related to normal business operations and large construction obligations.

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2016.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $86.3 million at December 31, 2014, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 15, Commitments and Contingencies, for more information about environmental liabilities.

Capital Requirements

As of December 31, 2014, our projected capital expenditures by segment for 2015 through 2017 were as follows:

(Millions)	2015	2016	2017	Total
Electric Utility				
Distribution and energy supply operations projects	$ 171	$ 306	$ 397	$ 874
Environmental projects	171 *	42 *	23	236
Other projects	7	3	3	13
Natural Gas Utility				
Distribution projects	36	33	32	101
Other projects	2	1	1	4
Total capital expenditures	$ 387	$ 385	$ 456	$ 1,228

* This primarily relates to the installation of ReACT™ emission control technology at Weston 3.

All projected capital expenditures are subject to periodic review and may vary significantly from the estimates, depending on a number of factors. These factors include, but are not limited to, environmental requirements, regulatory constraints and requirements, changes in tax laws and regulations, market volatility, and economic trends.

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management strategies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage our liquidity and capital resource needs. We plan to meet our capital requirements for the period 2015 through 2017 primarily through internally generated funds (net of forecasted dividend payments), debt financings, and equity infusions from Integrys Energy Group. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

We currently have a shelf registration statement under which we may issue up to $500.0 million of additional senior debt securities and/or first mortgage bonds. Amounts, prices, and terms will be determined at the time of future offerings.

Under the merger agreement between our parent and Wisconsin Energy Corporation (Wisconsin Energy), we cannot issue long-term debt in excess of $300.0 million in 2015 without Wisconsin Energy's approval.

At December 31, 2014, we were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 11, Short-Term Debt and Lines of Credit, for more information on credit facilities and other short-term credit agreements. See Note 12, Long-Term Debt, for more information on long-term debt.

Other Future Considerations

Potential Addition of an Electric Generator to Fox Energy Center Site

In 2013, we announced a need for an additional 400 to 500 megawatts (MW) of electric generating capacity by 2019 to meet the energy needs of our customers. After evaluating various options, we proposed building a new 400-MW natural gas-fired, combined-cycle generating unit for approximately $517 million to be located at our Fox Energy Center site. In January 2015, we filed an application with the PSCW for a Certificate of Public Convenience and Necessity. The approval process involves months of PSCW study and review, as well as technical and public hearings with a decision expected by the end of 2015. If approved in that time frame, construction will begin in 2016 with plans for the new unit to be operational in 2019.

Presque Isle System Support Resources (SSR) Costs

In August 2013, Wisconsin Electric Power Company (Wisconsin Electric Power) notified MISO of its intention to suspend the operation of Units 5 through 9 of its Presque Isle generating facility for 16 months, starting February 1, 2014. MISO notified Wisconsin Electric Power in October 2013 that the Presque Isle facilities are required for reliability and would be SSR-designated. Under the terms of the SSR Tariff, in exchange for keeping the units in service, MISO compensates Wisconsin Electric Power by allocating the SSR costs associated with the operation of the Presque Isle units to regulated and nonregulated load serving entities, including us, based on load ratio share within the ATC footprint.

On February 17, 2015, Wisconsin Electric Power notified MISO of its intent to rescind its decision to retire the Presque Isle facility and requested termination of the SSR agreement, effective February 1, 2015. This intent to rescind was driven by a settlement agreement related to the proposed merger between Wisconsin Energy Corporation and our parent (described below under the heading "Proposed Sale of WPS Michigan Electric

Assets"). On February 18, 2015, MISO filed to terminate the SSR agreement effective February 1, 2015. The FERC has not yet addressed these requests.

SSR costs for our retail customers will be deferred until December 31, 2015, based on an April 2013 order from the PSCW. At that time, the PSCW will determine the appropriate ratemaking treatment. As of December 31, 2014, there was no material SSR costs for our retail customers deferred for future recovery under the currently approved allocation method. SSR costs for Michigan customers are being recovered through the Power Supply Cost Recovery mechanism. SSR costs for our wholesale customers are being recovered through formula rates.

Proposed Sale of WPS Michigan Electric Assets

In January 2015, Wisconsin Energy Corporation (Wisconsin Energy) entered into an agreement with the Governor of Michigan, the Attorney General of Michigan, the MPSC staff, and Cliffs Natural Resources, Inc. to resolve these parties' objections to the proposed merger between Wisconsin Energy and our parent. The agreement is contingent upon the settlement of a series of additional agreements. One of the agreements includes the sale of the Presque Isle facility currently owned by Wisconsin Energy, as well as the Michigan electric distribution assets of Wisconsin Energy and us, to UPPCO. The sale of these assets is subject to approval from the MPSC, PSCW, FERC, Federal Communications Commission, and Committee on Foreign Investment in the United States, as well as the requirements of the Hart-Scott-Rodino Act. The sale of our electric distribution assets is contingent upon the close of the merger between Wisconsin Energy and our parent. See Note 2, Proposed Merger of Parent Company with Wisconsin Energy Corporation, for more information.

MISO Transmission Owner Return on Equity Complaint

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting, among other things, to reduce the base return on equity (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. However, the FERC denied all other aspects of the complaint, including that the use of capital structures that include more than 50% common equity is unjust and unreasonable. The FERC ordered preliminary hearings to begin and expects to issue an initial decision by November 30, 2015.

In October 2014, the FERC also issued an order, in regard to a similar complaint, to reduce the base ROE for New England transmission owners from their existing rate of 11.14% to 10.57%. The FERC used a revised method for determining the appropriate ROE for FERC-jurisdictional electric utilities, which incorporates both short-term and long-term measures of growth in dividends.

The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues will be guided by the New England transmission decision. Any change to ATC's ROE could result in lower equity income and dividends from ATC in the future. Although we are currently unable to determine how the FERC may rule in this complaint, we believe it is probable that a refund will be required upon resolution of this issue. As a result, our equity earnings and corresponding equity method investment in ATC reflected an estimated $0.7 million pretax reduction for 2014.

Wisconsin Fuel Rule Under-collection "Cap"

We use a "fuel window" mechanism to recover fuel and purchased power costs for our Wisconsin retail electric operations. Under the fuel window rule, actual fuel and purchased power costs that exceed a 2% variance from costs included in the rates charged to customers are deferred for recovery or refund. However, if the deferral of costs in a given year would cause us to earn a greater return on common equity than authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount the return exceeds the authorized amount by the PSCW. This is a possibility in any given year; however, this provision of the fuel rule did not have an impact on us in 2014.

Climate Change

The EPA began regulating greenhouse gas emissions under the Clean Air Act in January 2011 by applying the Best Available Control Technology (BACT) requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In March 2012, the EPA issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units. In September 2013, the EPA re-proposed rules related to emission limits on new electric generating units, and the EPA is expected to finalize them in the middle of 2015. The proposed emission rate limits may not be achievable for coal-fired plants until applicable technology becomes commercially available. In June 2014, the EPA issued a proposed rule establishing greenhouse gas performance standards for modified and reconstructed power plants. Comments on this proposal were due in October 2014, and are currently being reviewed.

Also, in June 2014, the EPA released a proposed rule establishing greenhouse gas performance standards for existing power plants. The proposal applies to "affected electric generating units," which includes our coal-fired units at Weston and Pulliam plus the natural gas-fired Fox Energy Center. The EPA is proposing state-specific emission reduction goals. States would be required to meet an "interim goal" on average over the ten-year period from 2020 through 2029 and a "final goal" in 2030, which will achieve a nationwide emission reduction of about 30% from 2005 levels. In the proposed rule, the state of Wisconsin is assigned a relatively aggressive reduction goal, which, if adopted as final, could significantly increase costs for our customers. Consequently, we are working with the other state utilities, the WDNR, the PSCW, and other stakeholders to evaluate the potential impacts and develop comments and suggested revisions for the EPA's consideration. The EPA intends to issue final rules in the summer of 2015. State implementation plans are due by June 30, 2016, with the possibility of extensions to 2017 for a state-specific plan and to 2018 if they are using a multistate approach. Facility compliance deadlines will be included in the final state plans.

A risk exists that any greenhouse gas legislation or regulation will increase the cost of producing energy using fossil fuels. However, we believe that capital expenditures being made at our plants are appropriate under any reasonable mandatory greenhouse gas program. We also believe that our future expenditures that may be required to control greenhouse gas emissions or meet renewable portfolio standards will be recoverable in rates. We will continue to monitor and manage potential risks and opportunities associated with future greenhouse gas legislative or regulatory actions.

All of our generation and distribution facilities are located in the upper Midwest region of the United States. The same is true for most of our customers' facilities. The physical risks, if any, posed by climate change for these areas are not expected to be significant at this time. Ongoing evaluations will be conducted as more information on the extent of such physical changes becomes available.

Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act)

The Dodd-Frank Act was signed into law in July 2010. Some, but not all of the Commodity Futures Trading Commission (CFTC) rulemakings to implement the new law, which are essential to the Dodd-Frank Act's new framework for swaps regulation, have become effective or are becoming effective for certain companies and certain transactions. However, some of the key rules have not been finalized yet or are subject to ongoing interpretations, clarifications, no-action letters, and other guidance being issued by the CFTC and its staff. As a result, it is difficult to evaluate in a comprehensive way how the CFTC's final Dodd-Frank Act rules will ultimately affect us. Certain provisions of the Dodd-Frank Act relating to derivatives and the CFTC's proposed rules could significantly increase our regulatory costs and/or collateral requirements or limit our ability to enter into or maintain certain derivative positions, which we use to hedge commercial risks. We continue to monitor developments related to the Dodd-Frank Act rulemakings and their potential impact on our future financial results. We have implemented or modified compliance policies and procedures to address the requirements of the Dodd-Frank Act rules that have taken effect to date.

OFF BALANCE SHEET ARRANGEMENTS

See Note 19, Guarantees, for information regarding guarantees.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We have determined that the following accounting policies and estimates are critical to the understanding of our financial statements because their application requires significant judgment and reliance on estimations of matters that are inherently uncertain. Our management has discussed these critical accounting policies and estimates with the Audit Committee of the Board of Directors of Integrys Energy Group.

Goodwill Impairment

We completed our annual goodwill impairment test for our natural gas utility reporting unit as of April 1, 2014. No impairment was recorded as a result of this test. The fair value calculated in step one of the test exceeded the carrying value by a substantial amount. The fair value was calculated using an equal weighting of the income approach and the market approach.

For the income approach, we used internal forecasts to project cash flows. Any forecast contains a degree of uncertainty, and changes in these cash flows could significantly increase or decrease the fair value of the reporting unit. A fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value to decrease.

Key assumptions used in the income approach included return on equity (ROE), the long-term growth rate used to determine the terminal value at the end of the discrete forecast period, and the discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair value will decrease. The discount rate is determined based on the weighted-average cost of capital, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE is based on our current allowed ROE adjusted for forecasted disallowed costs and expectations regarding the direction and magnitude of movements in interest rates. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income.

We used the guideline company method for the market approach. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company. We applied multiples derived from these guideline companies to the appropriate operating metric to determine an indication of fair value.

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

Accrued Unbilled Revenues

We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. Significant changes in these judgments and assumptions could have a material impact on our results of operations. The use of Automated Meter Reading technology has greatly reduced the judgments and assumptions required related to weather and customer use. At December 31, 2014, and 2013, our unbilled revenues were $72.3 million and $79.0 million, respectively. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer use patterns, commodity prices, and customer mix.

Pension and Other Postretirement Benefits

The costs of providing noncontributory defined benefit pension benefits and other postretirement benefits, described in Note 16, Employee Benefit Plans, are dependent on numerous factors resulting from actual plan experience and assumptions regarding future experience.

Pension and other postretirement benefit 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 other postretirement benefit costs may be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, discount rates, mortality rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and other postretirement benefit costs.

Pension and other postretirement benefit 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 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 ***(Millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2014 Pension Cost**
Discount rate	(0.5)	$ 46.1	$ 3.3
Discount rate	0.5	(40.9)	(2.5)
Rate of return on plan assets	(0.5)	N/A	4.0
Rate of return on plan assets	0.5	N/A	(4.0)

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

Actuarial Assumption ***(Millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2014 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 19.0	$ 2.3
Discount rate	0.5	(16.2)	(2.2)
Health care cost trend rate	(1.0)	(30.2)	(4.7)
Health care cost trend rate	1.0	37.4	5.6
Rate of return on plan assets	(0.5)	N/A	1.0
Rate of return on plan assets	0.5	N/A	(1.0)

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 other postretirement benefit obligation at December 31, 2014. The revised mortality assumptions will not have a material impact on our projected pension and other postretirement benefit obligations or costs.

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 asset assumption 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 was 8.00% in both 2014 and 2013 and 8.25% in 2012. The actual rate of return on pension plan assets, net of fees, was 6.2%, 15.2%, and 14.4%, in 2014, 2013, and 2012, respectively.

The determination of expected return on qualified plan assets is based on a market-related valuation of assets, which reduces year-to-year volatility, and is estimated using a calculated value approach. Cumulative gains and losses in excess of 10% of the greater of the pension or other postretirement benefit obligation or market-related value are amortized over the average remaining future service to expected retirement ages. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by us. However, for the Integrys Energy Group Retirement Plan sponsored by IBS, only differences between actual investment returns and expected returns on plan assets are recognized over a five-year period. Under this method, the future value of assets is impacted as previously deferred gains or losses are included in market-related value.

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 other postretirement benefits, see Note 16, Employee Benefit Plans.

Regulatory Accounting

Our electric and natural gas utility segments 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 utility segments, 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 electric and natural gas utility segments' operations no longer meet the criteria for application. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2014, would result in a 10.7% decrease in total assets and a 11.5% decrease in total liabilities. The largest regulatory asset at December 31, 2014, is related to unrecognized pension and other postretirement benefit costs. A write-off of that regulatory asset at December 31, 2014, would result in a 4.3% decrease in total assets. See Note 8, Regulatory Assets and Liabilities, for more information.

Income Tax Provision

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to 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(p), Income Taxes, and Note 14, Income Taxes, for a discussion of accounting for income taxes.

IMPACT OF INFLATION

Our financial statements are prepared in accordance with GAAP. The statements provide a reasonable, objective, and quantifiable picture of financial results, but generally do not evaluate the impact of inflation. To the extent we are not recovering the effects of inflation, we will file rate cases as necessary in the various jurisdictions in which we operate.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have potential market risk exposure related to commodity price risk, interest rate risk, and equity return and principal preservation risk. We have risk management policies in place to monitor and assist in controlling these risks, and we use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

Prudent fuel and purchased power costs and capacity payments are recovered from customers under one-for-one recovery mechanisms by our wholesale electric operations and Michigan retail electric operations. Prudently incurred costs of natural gas used by our natural gas operations are also recovered from customers under one-for-one recovery mechanisms. These recovery mechanisms greatly reduce our commodity price risk.

Our Wisconsin retail electric operations do not have a one-for-one recovery mechanism for price fluctuations. Instead, a "fuel window" mechanism substantially mitigates this price risk. See Note 1(e), Revenues and Customer Receivables, for more information.

To manage commodity price risk for our customers, we enter into fixed-price contracts of various durations for the purchase and/or sale of natural gas, fuel for electric generation, and electricity. Pursuant to the risk plans approved by the PSCW, we also use risk management techniques, which include the use of derivative instruments such as futures and options.

Interest Rate Risk

We are exposed to interest rate risk resulting from our short-term commercial paper 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.

Based on our variable rate debt outstanding at December 31, 2014, a hypothetical increase in interest rates of 100 basis points would have increased interest expense by $1.5 million. Comparatively, based on the variable rate debt outstanding at December 31, 2013, an increase in interest rates of 100 basis points would have resulted in an insignificant increase in our annual interest expense. 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.

Equity Return and Principal Preservation Risk

We currently fund liabilities related to employee benefits through various external trust funds. The trust funds are managed by numerous investment managers and primarily hold investments in debt and equity securities. Changes in the market value of these investments can have an impact on the future expenses related to these liabilities. Declines in the equity markets or declines in interest rates may result in increased future costs for the plans and require additional contributions into the plans. We monitor the trust fund portfolio by benchmarking the performance of the investments against certain security indices. Our employee benefit costs are recovered in customers' rates, reducing the equity return and principal preservation risk on these exposures. Also, the likelihood of an increase in the employee benefit obligations, which the investments must fund, has been partially mitigated as a result of certain employee groups no longer being eligible to participate in, or accumulate benefits in, certain pension and other postretirement benefit plans. Our defined benefit pension plans are closed to all new hires, and the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our control systems were designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013)*. Based on this assessment, management believes that, as of December 31, 2014, our internal control over financial reporting is effective.

B. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 ***(Millions)***	**2014**	2013	2012
Operating revenues	**$ 1,682.3**	$ 1,579.3	$ 1,499.2
Cost of fuel, natural gas, and purchased power	**773.6**	722.5	702.4
Operating and maintenance expense	**489.9**	462.5	429.1
Depreciation and amortization expense	**113.7**	106.2	96.2
Taxes other than income taxes	**46.7**	48.1	47.3
Operating income	**258.4**	240.0	224.2
Miscellaneous income	**24.4**	23.5	15.7
Interest expense	**57.4**	43.7	42.5
Other expense	**(33.0)**	(20.2)	(26.8)
Income before taxes	**225.4**	219.8	197.4
Provision for income taxes	**84.7**	81.9	62.6
Net income	**140.7**	137.9	134.8
Preferred stock dividend requirements	**(3.1)**	(3.1)	(3.1)
Net income attributed to common shareholder	**$ 137.6**	$ 134.8	$ 131.7

The accompanying notes to the consolidated financial statements are an integral part of these statements.

C. CONSOLIDATED BALANCE SHEETS

At December 31 ***(Millions, except share and per share data)***	**2014**	**2013**
Assets		
Cash and cash equivalents	**$ 5.4**	$ 5.7
Accounts receivable and accrued unbilled revenues, net of reserves of $3.2 and $2.5, respectively	**201.7**	209.8
Receivables from related parties	**1.3**	5.2
Inventories		
Fuel and gas	**85.0**	60.0
Materials and supplies, at average cost	**39.2**	34.9
Regulatory assets	**25.0**	46.2
Prepaid taxes	**65.7**	63.6
Other current assets	**18.3**	16.7
Current assets	**441.6**	442.1
Property, plant, and equipment, net of accumulated depreciation of $1,542.5 and $1,483.1, respectively	**3,131.0**	2,887.7
Regulatory assets	**433.5**	342.5
Goodwill	**36.4**	36.4
Pension and other postretirement benefit assets	**128.9**	145.1
Other long-term assets	**107.3**	107.5
Total assets	**$ 4,278.7**	$ 3,961.3
Liabilities and Shareholders' Equity		
Short-term debt	**$ 145.1**	$ 25.6
Current portion of long-term debt	**125.0**	—
Current portion of long-term debt to parent	**2.5**	—
Accounts payable	**161.6**	131.8
Payables to related parties	**16.9**	13.8
Regulatory liabilities	**21.2**	38.0
Other current liabilities	**69.3**	72.0
Current liabilities	**541.6**	281.2
Long-term debt to parent	**2.9**	6.3
Long-term debt	**1,049.5**	1,174.5
Deferred income taxes	**722.1**	619.5
Deferred investment tax credits	**7.8**	8.1
Regulatory liabilities	**303.3**	286.3
Environmental remediation liabilities	**86.3**	64.4
Pension and other postretirement benefit obligations	**37.6**	76.4
Payables to related parties	**5.4**	6.1
Other long-term liabilities	**71.6**	71.9
Long-term liabilities	**2,286.5**	2,313.5
Commitments and contingencies		
Preferred stock – $100 par value; 1,000,000 shares authorized; 511,882 shares issued and outstanding	**51.2**	51.2
Common stock – $4 par value; 32,000,000 shares authorized; 23,896,962 shares issued and outstanding	**95.6**	95.6
Additional paid-in capital	**782.0**	723.5
Retained earnings	**521.8**	496.3
Total liabilities and shareholders' equity	**$ 4,278.7**	$ 3,961.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

D. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(Millions, except share and per share data)*			2014	2013
Common stock equity				
Common stock – $4 par value; 32,000,000 shares authorized; 23,896,962 shares outstanding			**$ 95.6**	$ 95.6
Additional paid-in capital			**782.0**	723.5
Retained earnings			**521.8**	496.3
Total common stock equity			**1,399.4**	1,315.4
Preferred stock				
Cumulative; $100 par value; 1,000,000 shares authorized with no mandatory redemption –				
	Series	**Shares Outstanding**		
	5.00%	131,916	**13.2**	13.2
	5.04%	29,983	**3.0**	3.0
	5.08%	49,983	**5.0**	5.0
	6.76%	150,000	**15.0**	15.0
	6.88%	150,000	**15.0**	15.0
Total preferred stock		511,882	**51.2**	51.2
Long-term debt to parent				
	Series	**Year Due**		
	8.76%	2015	**2.0**	2.4
	7.35%	2016	**3.4**	3.9
Total			**5.4**	6.3
Current portion of long-term debt to parent			**(2.5)**	—
Total long-term debt to parent			**2.9**	6.3
Long-term debt				
First Mortgage Bonds				
	Series	**Year Due**		
	7.125%	2023	**0.1**	0.1
Senior Notes				
	Series	**Year Due**		
	6.375%	2015	**125.0**	125.0
	5.65%	2017	**125.0**	125.0
	6.08%	2028	**50.0**	50.0
	5.55%	2036	**125.0**	125.0
	3.671%	2042	**300.0**	300.0
	4.752%	2044	**450.0**	450.0
Total First Mortgage Bonds and Senior Notes			**1,175.1**	1,175.1
Unamortized discount on long-term debt			**(0.6)**	(0.6)
Total			**1,174.5**	1,174.5
Current portion of long-term debt			**(125.0)**	—
Total long-term debt			**1,049.5**	1,174.5
Total capitalization			**$ 2,503.0**	$ 2,547.4

The accompanying notes to the consolidated financial statements are an integral part of these statements.

E. CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY

(Millions)	Common Stock	Additional Paid in Capital	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2011	$ 95.6	$ 561.9	$ 444.6	$ 1,102.1
Net income attributed to common shareholder	—	—	131.7	131.7
Equity contribution from parent	—	40.0	—	40.0
Return of capital to parent	—	(50.0)	—	(50.0)
Dividends to parent	—	—	(105.5)	(105.5)
Other	—	3.5	(0.3)	3.2
Balance at December 31, 2012	$ 95.6	$ 555.4	$ 470.5	$ 1,121.5
Net income attributed to common shareholder	—	—	134.8	134.8
Equity contribution from parent	—	200.0	—	200.0
Return of capital to parent	—	(35.0)	—	(35.0)
Dividends to parent	—	—	(108.6)	(108.6)
Other	—	3.1	(0.4)	2.7
Balance at December 31, 2013	$ 95.6	$ 723.5	$ 496.3	$ 1,315.4
Net income attributed to common shareholder	**—**	**—**	**137.6**	**137.6**
Equity contribution from parent	**—**	**55.0**	**—**	**55.0**
Dividends to parent	**—**	**—**	**(111.8)**	**(111.8)**
Other	**—**	**3.5**	**(0.3)**	**3.2**
Balance at December 31, 2014	**$ 95.6**	**$ 782.0**	**$ 521.8**	**$ 1,399.4**

The accompanying notes to the consolidated financial statements are an integral part of these statements.

F. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(Millions)*	2014	2013	2012
Operating Activities			
Net Income	**$ 140.7**	$ 137.9	$ 134.8
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization expense	**113.7**	106.2	96.2
Recoveries and refunds of regulatory assets and liabilities	**6.1**	(13.2)	15.1
Bad debt expense	**7.3**	5.2	5.7
Pension and other postretirement (credit) expense	**(6.2)**	22.2	18.9
Pension and other postretirement contributions	**(49.5)**	(43.5)	(122.0)
Deferred income taxes and investment tax credit	**90.5**	79.4	33.4
Repayment of related party payables	**—**	—	(22.6)
Termination of tolling agreement with Fox Energy Company LLC	**—**	(50.0)	—
Deferrals to regulatory assets and liabilities	**(16.4)**	12.8	(10.3)
Other	**(14.3)**	(9.6)	5.1
Changes in working capital			
Accounts receivable and accrued unbilled revenues	**5.6**	(24.8)	2.9
Inventories	**(29.1)**	18.9	11.9
Prepaid taxes	**(2.1)**	21.1	27.9
Other current assets	**(3.4)**	(0.5)	(0.2)
Accounts payable	**15.4**	(14.9)	3.0
Other current liabilities	**5.2**	25.9	23.5
Net cash provided by operating activities	**263.5**	273.1	223.3
Investing Activities			
Capital expenditures	**(329.1)**	(241.6)	(179.5)
Acquisition of Fox Energy Company LLC	**—**	(391.6)	—
Grant received related to Crane Creek wind project	**—**	69.0	—
Other	**8.0**	7.6	7.3
Net cash used for investing activities	**(321.1)**	(556.6)	(172.2)
Financing Activities			
Short-term debt, net	**119.5**	(69.8)	(78.3)
Borrowing on term credit facility	**—**	200.0	—
Repayment of term credit facility	**—**	(200.0)	—
Repayment of long-term debt	**—**	(147.0)	(150.0)
Repayment of long-term debt to parent	**(0.9)**	(0.9)	(0.7)
Issuance of long-term debt	**—**	450.0	300.0
Payments of dividend to parent	**(111.8)**	(108.6)	(105.5)
Equity contribution from parent	**55.0**	200.0	40.0
Return of capital to parent	**—**	(35.0)	(50.0)
Preferred stock dividend requirements	**(3.1)**	(3.1)	(3.1)
Other	**(1.4)**	(2.9)	(2.5)
Net cash provided by (used for) financing activities	**57.3**	282.7	(50.1)
Net change in cash and cash equivalents	**(0.3)**	(0.8)	1.0
Cash and cash equivalents at beginning of year	**5.7**	6.5	5.5
Cash and cash equivalents at end of year	**$ 5.4**	$ 5.7	$ 6.5
Cash paid for interest	**$ 56.8**	$ 43.9	$ 40.2
Cash (received) paid for income taxes	**$ (6.2)**	$ (27.3)	$ 2.9

The accompanying notes to the consolidated financial statements are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2014

Note 1—Summary of Significant Accounting Policies

(a) Nature of Operations—We are an electric and natural gas utility company, serving customers in northeastern Wisconsin and Michigan's Upper Peninsula. We are subject to the jurisdiction of, and regulation by, the PSCW and the MPSC, which have general supervisory and regulatory powers over virtually all phases of the public utility industry in Wisconsin and Michigan, respectively. We are also subject to the jurisdiction of the FERC, which regulates our natural gas pipelines and wholesale electric rates.

(b) Basis of Presentation—As used in these notes, the term “financial statements” refers to the consolidated financial statements. This includes the consolidated statements of income, consolidated balance sheets, consolidated statements of capitalization, consolidated statements of common shareholder's equity, and consolidated statements of cash flows, unless otherwise noted.

At December 31, 2014, we had one wholly owned subsidiary, WPS Leasing. The financial statements include our accounts and the accounts of our wholly owned subsidiary, after eliminating intercompany transactions and balances. These financial statements also reflect our proportionate interests in certain jointly owned utility facilities. 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 businesses 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.

(c) Use of Estimates—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect assets, 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.

(d) Cash and Cash Equivalents—Short-term investments with an original maturity of three months or less are reported as cash equivalents.

(e) Revenues and Customer Receivables—Revenues related to the sale of energy are recognized when service is provided or energy is delivered to customers. We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. At December 31, 2014, and 2013, our unbilled revenues were $72.3 million and $79.0 million, respectively.

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

Below is a summary of the significant mechanisms we had in place in 2014 that allowed us 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 wholesale electric operations and Michigan retail electric operations.
- Our Wisconsin retail electric operations used a "fuel window" mechanism to recover fuel and purchased power costs. Under the fuel window rule, a deferral is required for 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. We monitor the deferral of these costs to ensure that it does not cause us to earn a greater return on common equity than authorized by the PSCW.
- Our rates included a one-for-one recovery mechanism for natural gas commodity costs.

Revenues are also impacted by other accounting policies related to our participation in the MISO market. We sell and purchase power in the MISO market. If we were a net seller in a particular hour, the net amount was reported as revenue. If we were a net purchaser in a particular hour, the net amount was recorded as cost of fuel, natural gas, and purchased power on the income statements.

We provide regulated electric and natural gas service to customers in northeastern Wisconsin 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. As a result, we did not have any significant concentrations of credit risk at December 31, 2014. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2014.

(f) Inventories—Inventories consist of materials and supplies, emission allowances, natural gas in storage, and other fossil fuels, including coal. Average cost is used to value materials and supplies, emission allowances, fossil fuels, and natural gas in storage.

(g) Risk Management Activities—As part of our regular operations, we enter into contracts, including options, futures, forwards, and other contractual commitments, to manage changes in commodity prices. See Note 5, Risk Management Activities, for more information. Derivative instruments are entered into in accordance with the terms of the risk management policies approved by our Board of Directors and the PSCW or MPSC.

All derivatives are recognized on the balance sheets at their 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. Because most of our energy-related derivatives qualify for regulatory deferral, management believes any gains or losses resulting from the eventual settlement of derivative instruments will be refunded to or collected from customers in rates. As such, any changes in the fair value of these derivatives recorded as either risk management assets or liabilities are offset with regulatory liabilities or assets, as appropriate.

We classify derivative assets and liabilities as current or long-term on the balance sheets based upon the maturities of the underlying contracts. We record unrealized gains and losses on derivative instruments that do not qualify for regulatory deferral as a component of our cost of fuel, natural gas, and purchased power or operating and maintenance expense, depending on the nature of the transaction. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the 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 the balance sheets, cash collateral provided to others is reflected in other current assets, and cash collateral received from others is reflected in other current liabilities.

(h) Emission Allowances—We account for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating our generation plants. These charges are included in the costs subject to the fuel window rules. Gains on sales of allowances are returned to ratepayers.

(i) Property, Plant, and Equipment—Utility plant is stated at cost, including any associated AFUDC and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Maintenance and repair costs, as well as replacement and renewal costs associated with items not qualifying as units of property, are recorded as operating expenses. We record a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. Ordinary retirements, sales, and other disposals of units of property at the utilities are charged to accumulated depreciation at cost, less salvage value. When it becomes probable that an operating unit will be retired in the near future and substantially in advance of its expected useful life, the cost and corresponding accumulated depreciation of the asset is classified as plant to be retired, net within property, plant, and equipment.

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	**2014**	**2013**	**2012**
Electric	**2.73%**	2.79%	2.87%
Natural gas	**2.17%**	2.19%	2.21%

We capitalize certain costs related to software developed or obtained for internal use and amortize those costs to operating expense over the estimated useful life of the related software, which ranges from 3 to 5 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

We receive grants related to certain renewable generation projects under federal and state grant programs. Our policy is to reduce the depreciable basis of the qualifying project by the grant received. We then reflect the benefit of the grant in income over the life of the related renewable generation project through a reduction in depreciation expense.

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

(j) AFUDC—We capitalize the cost of funds used for construction using a calculation that includes both internal equity and external debt components, as required by regulatory accounting. The internal equity component is accounted for as other income. The external debt component is accounted for as a decrease to interest expense.

Approximately 50% of our retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. For 2014, our average AFUDC retail rate was 8.08%, and our average AFUDC wholesale rate was 6.99%.

Our total AFUDC was as follows for the years ended December 31:

	2014	**2013**	**2012**
Allowance for equity funds used during construction	**$ 11.0**	$ 9.9	$ 2.6
Allowance for borrowed funds used during construction	**4.6**	3.8	0.9

(k) Regulatory Assets and Liabilities—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 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 year the determination is made. See Note 8, Regulatory Assets and Liabilities, for more information.

(l) Goodwill—Goodwill is subject to an annual impairment test. Our natural gas utility reporting unit contains goodwill and performs its annual goodwill impairment test during the second quarter of each year. Interim impairment tests are performed when impairment indicators are present. 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.

(m) Retirement of Debt—Any call premiums or unamortized expenses associated with refinancing utility debt obligations are amortized consistent with regulatory treatment of those items. Any gains or losses resulting from the retirement of utility debt that is not refinanced are amortized over the remaining life of the original debt.

(n) Asset Retirement Obligations—We recognize at fair value legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded 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 asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. 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 in the carrying amount of the liability and the associated retirement cost. See Note 13, Asset Retirement Obligations, for more information.

(o) 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 (PRP). Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites. See Note 15, Commitments and Contingencies, for more information on our manufactured gas plant sites.

We record environmental remediation liabilities when site assessments indicate remediation is probable and we can reasonably estimate the loss or a range of possible losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other PRPs 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.

We 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 respective Commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and 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.

(p) Income Taxes—We and our subsidiary are included in the consolidated United States income tax return filed by Integrys Energy Group. We and our subsidiary are parties to a federal and state tax allocation arrangement with Integrys Energy Group and its subsidiaries under which each entity determines its provision for income taxes on a stand-alone basis. We settle the intercompany liabilities at the time payments are made to the applicable taxing authority. See Note 25, Related Party Transactions, for more information regarding intercompany payables or receivables related to income taxes.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. We record valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. We defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

We use the deferral method of accounting for investment tax credits (ITCs). Under this method, we record the ITCs as deferred credits and amortize such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. ITCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

We report interest and penalties accrued related to income taxes as a component of provision for income taxes in the income statements, as well as regulatory assets or regulatory liabilities in the balance sheets.

We record excess tax benefits from stock-based compensation awards when the actual tax benefit is realized. We follow the tax law ordering approach to determine when the tax benefit has been realized. Under this approach, the tax benefit is realized in the year it reduces taxable income. Current year stock-based compensation deductions are assumed to be used before any net operating loss carryforwards.

See Note 14, Income Taxes, for more information regarding our accounting for income taxes.

(q) 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 19, Guarantees, for more information.

(r) Employee Benefits—The costs of pension and other postretirement benefits are expensed over the periods during which employees render service. Our transition obligation related to other postretirement benefit plans was recognized over a 20-year period that began in 1993, and ended in 2012. In computing the expected return on plan assets, we use a market-related value of plan assets, which is a calculated value approach. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by us, while differences between actual investment returns and the expected return on plan assets are recognized over a five-year period for the Integrys Energy Group Retirement Plan, sponsored by IBS. The benefit costs associated with employee benefit plans are allocated among Integrys Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the net periodic benefit cost calculated under GAAP.

We recognize the funded status of defined benefit postretirement plans on the balance sheet, and recognize changes in the plans' funded status in the year in which the changes occur. We record changes in the funded status to regulatory asset or liability accounts, pursuant to the Regulated Operations Topic of the FASB ASC.

We account for our participation in benefit plans sponsored by IBS and other postretirement benefit plans we sponsor as multiple employer plans. Under affiliate agreements, we are responsible for our share of plan costs and obligations and are entitled to our share of plan assets. Accordingly, we account for our pro rata share of these plans as our own plan.

See Note 16, Employee Benefit Plans, for more information.

(s) Stock-Based Compensation—Our employees may be granted awards under Integrys Energy Group’s stock-based compensation plans. At December 31, 2014, stock options, performance stock rights, and restricted share units were outstanding under various plans. Compensation cost associated with these awards is allocated to us based on the percentages used for allocation of the award recipients’ labor costs.

Stock Options

All stock options granted to our employees are for the option to purchase shares of Integrys Energy Group common stock. Stock options have a term not longer than 10 years. The exercise price of each stock option is equal to the fair market value of the stock on the date the stock option is granted.

Effective October 24, 2014, Integrys Energy Group's Board of Directors accelerated the vesting of all unvested stock options held by active employees in order to mitigate the tax impacts of Section 280G of the Internal Revenue Code on us, Integrys Energy Group, and certain employees. All stock options awarded to active employees also became exercisable as of this date. For retirees, 25% of their stock options granted will continue to become exercisable each year on the anniversary of the grant date.

The fair value of stock option awards granted is estimated using a binomial lattice model. The expected term of option awards is derived from the output of the binomial lattice model and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate of Integrys Energy Group. The expected stock price volatility is estimated using its 10-year historical volatility.

Performance Stock Rights

Performance stock rights generally vest over a three-year performance period. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the distribution of these awards is not accelerated. Effective October 24, 2014, Integrys Energy Group's Board of Directors approved the acceleration of the distribution of certain performance stock rights held by active employees. For those performance stock rights with a performance period ending December 31, 2014, a portion of the estimated distribution was made in December 2014. This change was made to help mitigate the tax impacts of Section 280G of the Internal Revenue Code on us, Integrys Energy Group, and certain employees.

Performance stock rights are paid out in shares of Integrys Energy Group common stock, or eligible employees can elect to defer the value of their awards into the deferred compensation plan and choose among various investment options, some of which are ultimately paid out in Integrys Energy Group common stock and some of which are ultimately paid out in cash. Eligible employees can only elect to defer up to 80% of the value of their awards. The number of shares paid out is calculated by multiplying a performance percentage by the number of outstanding stock rights at the completion of the performance period. The performance percentage is based on the total shareholder return of Integrys Energy Group's common stock relative to the total shareholder return of a peer group of companies. The payout may range from 0% to 200% of target.

Performance stock rights are accounted for as either an equity award or a liability award, depending on their settlement features. Awards that can only be settled in shares of Integrys Energy Group common stock are accounted for as equity awards. Awards that an employee has elected to defer, or is still able to defer, into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

Six months prior to the end of the performance period, employees can no longer change their election to defer the value of their performance stock rights into the deferred compensation plan. As a result, any awards not elected for deferral at this point in the performance period will be settled in Integrys Energy Group's common stock. This changes the classification of these awards from a liability award to an equity award. The change in classification is accounted for as an award modification. The fair value on the modification date is used to measure these awards for the remaining six months of the performance period. No incremental compensation expense is recorded as a result of this award modification.

The fair values of performance stock rights are estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate of Integrys Energy Group. The expected volatility is estimated using one to three years of historical data.

Restricted Share Units

Restricted share units generally have a four-year vesting period, with 25% of each award vesting on each anniversary of the grant date. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the release of shares to these employees is not accelerated. Restricted share unit recipients do not have voting rights, but they receive forfeitable Integrys Energy Group dividend equivalents in the form of additional restricted share units.

Restricted share units are accounted for as either an equity award or a liability award, depending on their settlement features. Awards that can only be settled in shares of Integrys Energy Group common stock and cannot be deferred into the deferred compensation plan are accounted for as equity awards. Eligible employees can only elect to defer up to 80% of their awards into the deferred compensation plan. Equity awards are measured based on the fair value on the grant date. Awards that an employee has elected to defer into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

(t) Fair Value—A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information.

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). 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.

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 methodologies that result in management's best estimate of fair value.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Our risk management assets and liabilities include NYMEX futures and options, physical commodity contracts, and financial transmission rights (FTRs) used to manage transmission congestion costs in the MISO market. NYMEX contracts are valued using the NYMEX end-of-day settlement price, which is a Level 1 input. Level 2 contracts are valued based on quoted market prices received from counterparties and price index developers. The valuation for physical coal contracts is categorized in Level 3 as it is based on significant assumptions made to extrapolate prices from the last quoted period through the end of the transaction term. The valuation for FTRs is derived from historical data from MISO, which is also considered a Level 3 input.

We have established a risk oversight committee whose primary responsibility includes directly or indirectly ensuring that all valuation methods are applied in accordance with predefined policies. The development and maintenance of our forward price curves has been assigned to our risk management department, which is part of the corporate treasury function. This group is separate and distinct from the supply function. To validate the reasonableness of our fair value inputs, our risk management department compares changes in valuation and researches any significant differences in order to determine the underlying cause. Changes to the fair value inputs are made if necessary.

Derivatives are transferred between levels of the fair value hierarchy due to observable pricing becoming available as the remaining contract term becomes shorter. We recognize transfers at the value as of the end of the reporting period.

The fair values of long-term debt are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity. The fair values of preferred stock are estimated based on quoted market prices, when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy. Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, and outstanding commercial paper, the carrying amount for each such item approximates fair value.

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

See Note 21, Fair Value, for more information.

(u) New Accounting Pronouncements—

Recently Issued Accounting Guidance Not Yet Effective

In February 2015, the FASB issued ASU 2015-02, "Amendments to the Consolidation Analysis." The guidance focuses on the consolidation evaluation for companies that are required to evaluate whether they should consolidate certain legal entities. This ASU eliminates the specialized guidance for limited partnerships and similar legal entities. It places more emphasis on risk of loss when determining a controlling financial interest and amends the guidance for assessing how relationships of related parties affect the consolidation analysis of variable interest entities. The guidance is effective for us for the reporting period ending March 31, 2016. We are currently evaluating the impact this guidance will have on our financial statements.

In January 2015, the FASB issued ASU 2015-01, "Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items." This guidance no longer requires or allows the disclosure of extraordinary items, net of tax, in the income statement after income from continuing operations. The guidance is effective for us for the reporting period ending March 31, 2016. We do not currently have any extraordinary items presented on the income statements. However, this guidance will eliminate the need for us to further assess whether unusual and infrequently occurring transactions qualify as an extraordinary item in the future.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers." This ASU supersedes the requirements in the Revenue Recognition Topic of the FASB ASC and most industry-specific guidance throughout the ASC. The guidance is based on the principle that revenue is recognized when promised goods or services are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and cash flows from customer contracts. The guidance is effective for us for the reporting period ending March 31, 2017. The standard requires either retrospective application by restating each prior period presented in the financial statements, or modified retrospective application by recording the cumulative effect of prior reporting periods to beginning retained earnings in the year that the standard becomes effective. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

Note 2—Proposed Merger of Parent Company with Wisconsin Energy Corporation

In June 2014, our parent company, Integrys Energy Group, entered into an Agreement and Plan of Merger with Wisconsin Energy Corporation (Wisconsin Energy). This transaction was approved unanimously by the Boards of Directors of both companies. It was also approved by the shareholders of both companies. On October 24, 2014, the Department of Justice closed its review of the transaction and the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Act. The transaction is still subject to approvals from the FERC, Federal Communications Commission (FCC), PSCW, and other regulatory commissions, as well as other customary closing conditions. In the MPSC approval docket, we and our parent are parties to a contested settlement agreement with the MPSC staff and all but one of the parties, under which the settling parties agree that the MPSC should grant approval of the merger contingent on additional transactions, including the sale of the Presque Isle facility currently owned by Wisconsin Energy, as well as our and Wisconsin Energy's Michigan electric distribution assets, to UPPCO. The asset sales require additional approvals, including the MPSC, PSCW, FERC, FCC, and Committee on Foreign Investment in the United States, as well as the requirements of the Hart-Scott-Rodino Act. We expect the merger transaction to close in the second half of 2015.

Note 3—Acquisition of Fox Energy Center

In March 2013, we acquired all of the equity interests in Fox Energy Company LLC for $391.6 million. Fox Energy Company LLC was dissolved immediately after the purchase.

The purchase included the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility located in Wisconsin, along with associated contracts. Fox Energy Center is a dual-fuel facility, equipped to use fuel oil, but being run primarily on natural gas. This plant gives us a more balanced mix of owned electric generation, including coal, natural gas, hydroelectric, wind, and other renewable sources. In giving its approval for the purchase, the PSCW stated that the purchase price was reasonable and will benefit ratepayers.

The purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition, as follows:

(Millions)		
Assets acquired [1]		
Inventories - materials and supplies	$	3.0
Other current assets		0.4
Property, plant, and equipment		374.4
Other long-term assets [2]		15.6
Total assets acquired	**$**	**393.4**
Liabilities assumed		
Accounts payable	$	1.8
Total liabilities assumed	**$**	**1.8**

(1) Relates to the electric utility segment.

(2) Intangible assets recorded for contractual services agreements. See Note 9, Goodwill and Other Intangible Assets, for more information.

Prior to the purchase, we supplied natural gas for the facility and purchased 500 megawatts of capacity and the associated energy output under a tolling arrangement. We paid $50.0 million for the early termination of the tolling arrangement. This amount was recorded as a regulatory asset, as we are authorized recovery by the PSCW. The amount is being amortized over a nine-year period that began on January 1, 2014.

We received regulatory approval to defer incremental costs incurred in 2013 associated with the purchase of the facility. These costs are included in our 2015 proposed retail electric rate increase. See Note 22, Regulatory Environment, for more information. Our rate order effective January 1, 2014, included the costs of owning and operating the Fox Energy Center.

Pro forma adjustments to our revenues and earnings prior to the date of acquisition would not be meaningful or material. Prior to the acquisition, the Fox Energy Center was a nonregulated plant and sold all of its output to third parties, with most of the output purchased by us. The plant is now part of our regulated fleet, used to serve our customers.

Note 4—Cash and Cash Equivalents

Construction costs funded through accounts payable totaled $54.0 million, $37.3 million, and $24.8 million in 2014, 2013, and 2012, respectively. These costs were treated as noncash investing activities.

Note 5—Risk Management Activities

We use physical and financial derivative contracts to manage commodity costs. None of these derivatives are designated as hedges for accounting purposes. The electric and natural gas utility segments use financial derivative contracts to manage the risks associated with the market price volatility of natural gas supply costs. The electric utility segment also uses financial derivative contracts to reduce price risk related to coal transportation costs and financial transmission rights (FTRs) to manage electric transmission congestion costs.

The tables below show our assets and liabilities from risk management activities:

(Millions)	Balance Sheet Presentation	December 31, 2014 Assets	December 31, 2014 Liabilities
Natural gas contracts	Other Current	$ 0.1	$ 2.1
Natural gas contracts	Other Long-term	—	0.1
FTRs	Other Current	2.2	0.3
Petroleum product contracts	Other Current	—	1.1
Coal contracts	Other Current	—	2.4
Coal contracts	Other Long-term	—	1.0
	Other Current	**2.3**	**5.9**
	Other Long-term	—	**1.1**
Total		**$ 2.3**	**$ 7.0**

(Millions)	Balance Sheet Presentation	December 31, 2013 Assets	December 31, 2013 Liabilities
Natural gas contracts	Other Current	$ 0.6	$ 0.1
FTRs	Other Current	1.5	0.3
Petroleum product contracts	Other Current	0.1	—
Coal contracts	Other Current	—	1.9
Coal contracts	Other Long-term	0.2	0.8
	Other Current	2.2	2.3
	Other Long-term	0.2	0.8
Total		$ 2.4	$ 3.1

The following tables show the potential effect on our financial position of netting arrangements for recognized derivative assets and liabilities:

(Millions)	December 31, 2014 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	**$ 2.3**	**$ 0.4**	**$ 1.9**
Derivative assets not subject to master netting or similar arrangements	—		—
Total risk management assets	**$ 2.3**		**$ 1.9**
Derivative liabilities subject to master netting or similar arrangements	**$ 3.6**	**$ 3.6**	**$ —**
Derivative liabilities not subject to master netting or similar arrangements	**3.4**		**3.4**
Total risk management liabilities	**$ 7.0**		**$ 3.4**

(Millions)	December 31, 2013 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	$ 2.2	$ 0.6	$ 1.6
Derivative assets not subject to master netting or similar arrangements	0.2		0.2
Total risk management assets	$ 2.4		$ 1.8
Derivative liabilities subject to master netting or similar arrangements	$ 0.4	$ 0.4	$ —
Derivative liabilities not subject to master netting or similar arrangements	2.7		2.7
Total risk management liabilities	$ 3.1		$ 2.7

Our master netting and similar arrangements have conditional rights of setoff that can be enforced under a variety of situations, including counterparty default or credit rating downgrade below investment grade. We have trade receivables and trade payables, subject to master netting or similar arrangements, that are not included in the above table. These amounts may offset (or conditionally offset) the net amounts presented in the above table.

Financial collateral received or provided is restricted to the extent that it is required per the terms of the related agreements. The following table shows our cash collateral positions:

(Millions)	December 31, 2014	December 31, 2013
Cash collateral provided to others related to contracts under master netting or similar arrangements	**$ 6.6**	$ 3.1
Cash collateral received from others related to contracts under master netting or similar arrangements	**—**	0.2

The following table shows the unrealized gains (losses) recorded related to derivative contracts:

(Millions)	Financial Statement Presentation	2014	2013	2012
Natural gas	Balance Sheet — Regulatory assets (current)	**$ (2.3)**	$ 0.7	$ 2.2
Natural gas	Balance Sheet — Regulatory liabilities (current)	**(0.3)**	0.3	0.1
Natural gas	Income Statement — Cost of fuel, natural gas, and purchased power	**—**	—	0.2
FTRs	Balance Sheet — Regulatory assets (current)	**—**	0.2	(0.1)
FTRs	Balance Sheet — Regulatory liabilities (current)	**0.4**	(0.3)	—
Petroleum	Balance Sheet — Regulatory assets (current)	**(1.1)**	—	0.1
Petroleum	Balance Sheet — Regulatory liabilities (current)	**(0.1)**	0.1	—
Coal	Balance Sheet — Regulatory assets (current)	**(1.3)**	(0.9)	(2.2)
Coal	Balance Sheet — Regulatory assets (long-term)	**(0.2)**	3.5	0.1
Coal	Balance Sheet — Regulatory liabilities (current)	**—**	(0.2)	0.3
Coal	Balance Sheet — Regulatory liabilities (long-term)	**(0.1)**	(2.0)	2.2

We had the following notional volumes of outstanding derivative contracts:

(Millions)	December 31, 2014		December 31, 2013		
Commodity	**Purchases**	**Other Transactions**	**Purchases**	**Sales**	**Other Transactions**
Natural gas (therms)	**1,025.4**	**N/A**	2,242.5	7.0	N/A
FTRs (kilowatt-hours)	**N/A**	**4,287.7**	N/A	N/A	3,427.0
Petroleum products (barrels)	**—**	**N/A**	0.1	—	N/A
Coal contract (tons)	**3.0**	**N/A**	4.8	—	N/A

Note 6—Property, Plant, and Equipment

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

(Millions)	2014	2013
Electric utility	**$ 3,587.4**	$ 3,289.2
Natural gas utility	**773.1**	729.9
Total utility plant	**4,360.5**	4,019.1
Less: Accumulated depreciation	**1,495.9**	1,436.8
Net	**2,864.6**	2,582.3
Construction work in progress	**248.7**	285.2
Plant to be retired, net *	**12.5**	14.4
Net utility plant	**3,125.8**	2,881.9
Nonutility plant	**15.2**	15.2
Less: Accumulated depreciation	**10.0**	9.4
Net nonutility plant	**5.2**	5.8
Total property, plant, and equipment	**$ 3,131.0**	$ 2,887.7

* In connection with the Consent Decree with the EPA, we announced that the Weston 1, Pulliam 5, and Pulliam 6 generating units will be retired early. These units are currently included in rate base and we continue to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. The amount presented above is net of accumulated depreciation. See Note 15, Commitments and Contingencies, for more information regarding the Consent Decree.

Note 7—Jointly Owned Utility Facilities

We hold a joint ownership interest in certain electric generating facilities. We are entitled to our share of generating capability and output of each facility equal to our respective ownership interest. We also pay our ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit our maximum exposure to additional costs. We record our proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets. The amounts were as follows at December 31, 2014:

(Millions, except for percentages and megawatts)	Weston 4	Columbia Energy Center Units 1 and 2	Edgewater Unit 4
Ownership	70.0%	31.8%	31.8%
Our share of rated capacity (megawatts)	374.5	335.2	105.0
In-service date	2008	1975 and 1978	1969
Utility plant	$ 581.9	$ 390.7	$ 42.9
Accumulated depreciation	$ (132.6)	$ (116.2)	$ (29.6)
Construction work in progress	$ 2.7	$ 10.1	$ 0.7

Our proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. We have supplied our own financing for all jointly owned projects.

Note 8—Regulatory Assets and Liabilities

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

(Millions)	2014	2013	See Note
Regulatory assets [(1)]			
Unrecognized pension and other postretirement benefit costs [(3)]	$ 185.6	$ 130.6	16
Environmental remediation costs (net of insurance recoveries) [(2) (4)]	103.8	80.1	15
Termination of a tolling agreement with Fox Energy Company LLC	44.6	50.0	3
Income tax related items	32.7	26.9	14
Crane Creek production tax credits [(5)]	32.2	33.6	
De Pere Energy Center [(6)]	21.4	23.8	
Energy costs recoverable through rate adjustments [(7)]	12.6	—	
Asset retirement obligations [(2)]	5.6	6.0	13
Derivatives [(2)]	8.0	3.3	1(g)
Potential new electric generator at Fox Energy Center [(8)]	3.7	—	
Pension and other postretirement costs recoverable through rate adjustments [(2) (9)]	—	9.4	22
Decoupling	—	7.9	22
Weston 3 lightning strike [(2) (10)]	—	3.6	
Other	8.3	13.5	
Total regulatory assets	$ 458.5	$ 388.7	
Balance Sheet Presentation			
Current assets	$ 25.0	$ 46.2	
Long-term assets	433.5	342.5	
Total regulatory assets	$ 458.5	$ 388.7	

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

(2) Regulatory assets not earning a return.

(3) Represents the unrecognized future pension and other postretirement costs resulting from actuarial gains and losses on defined benefit and other postretirement plans. We are authorized recovery of this regulatory asset over the average future remaining service life of each plan.

(4) As of December 31, 2014, we had not yet made cash expenditures for $86.3 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(5) In 2012, we elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, we reversed previously recorded production tax credits. We also reduced the depreciable basis of the qualifying facility by the amount of the grant proceeds, which will result in a reduction of depreciation and amortization expense over a 12-year period. We recorded a regulatory asset for the deferral of previously recorded production tax credits and are authorized recovery of this net regulatory asset through 2039.

(6) Prior to purchasing the De Pere Energy Center in 2002, we had a long-term power purchase contract with them that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed, and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. We are authorized recovery of this regulatory asset through 2023.

(7) Represents the under-collection of electric energy costs that will be recovered from customers in the future.

(8) Represents precertification costs for the proposed building of a new 400-MW natural gas-fired, combined-cycle generating unit to be located at our Fox Energy Center site. The building of this unit is currently in the approval process with the PSCW.

(9) Represents the under-collection of pension and other postretirement costs that will be recovered from customers in the future.

(10) In 2007, a lightning strike caused significant damage to the Weston 3 generating facility. The PSCW approved the deferral of the incremental fuel and purchased power expenses, as well as the nonfuel operating and maintenance expenses incurred as a result of the outage that were not covered by insurance. We were authorized recovery of this regulatory asset through 2014.

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

(Millions)	2014	2013	See Note
Regulatory liabilities			
Removal costs [1]	**$ 243.9**	$ 238.0	
Unrecognized pension and other postretirement benefit costs [2]	**42.4**	18.5	16
Decoupling	**12.3**	24.3	22
Crane Creek depreciation deferral [3]	**8.7**	9.0	
Energy costs refundable through rate adjustments [4]	**6.0**	21.9	
Fox Energy Center [5]	**4.6**	5.6	3
Energy efficiency programs	**3.7**	4.1	
Other	**2.9**	2.9	
Total regulatory liabilities	**$ 324.5**	$ 324.3	
Balance Sheet Presentation			
Current liabilities	**$ 21.2**	$ 38.0	
Long-term liabilities	**303.3**	286.3	
Total regulatory liabilities	**$ 324.5**	$ 324.3	

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

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

(3) Represents the book depreciation taken on the Crane Creek wind project prior to our election to claim a Section 1603 Grant for the project in lieu of the production tax credit. See more information in the regulatory assets section above.

(4) Represents the over-collection of energy costs that will be refunded to customers in the future.

(5) Represents the deferral of incremental costs associated with owning and operating the Fox Energy Center, which was purchased in March 2013. In accordance with GAAP, the deferral does not include an allowance for return on equity, which has created the net regulatory liability. This allowance was $22.8 million and $22.1 million, at December 31, 2014, and 2013, respectively.

Note 9—Goodwill and Other Intangible Assets

We had no changes to the carrying amount of goodwill during the years ended December 31, 2014, and 2013. In the second quarter of 2014, we completed our annual goodwill impairment test, and no impairment resulted from this test.

Our intangible assets listed below consist of contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at the Fox Energy Center. These contractual service agreements are included in other long-term assets on the balance sheets.

	December 31, 2014			December 31, 2013		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Contractual service agreements	**$ 15.6**	**$ (4.3)**	**$ 11.3**	$ 15.6	$ (1.8)	$ 13.8

In October 2014, we received approval from the PSCW to upgrade the combustion turbine generators at the Fox Energy Center earlier than planned. As a result of this approval, we shortened the amortization period of one of our service agreements. The remaining weighted-average amortization period for these intangible assets at December 31, 2014, was approximately four years. Since we have approval from the PSCW to recover the value of our service agreements from customers over seven years, the increase in amortization due to the shorter amortization period is recorded to a regulatory asset. This regulatory asset will be amortized to reflect the seven-year recovery period.

The table below shows the amortization recorded during the years ended December 31:

(Millions)	**2014**	2013
Amortization recorded in depreciation and amortization expense	**$ 2.2**	$ 1.8
Amortization recorded in regulatory assets	**0.3**	—

Amortization for the next five years is estimated to be:

	For the Year Ending December 31				
(Millions)	2015	2016	2017	2018	2019
Amortization to be recorded in depreciation and amortization expense	$ 2.2	$ 2.2	$ 1.7	$ 1.2	$ 1.2
Amortization to be recorded in regulatory assets	1.0	1.0	0.5	—	—

Note 10—Leases

We lease various property, plant, and equipment. Terms of the operating leases vary, but 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 $1.6 million, $2.3 million, and $2.4 million in 2014, 2013, and 2012, respectively. Future minimum rental obligations under noncancelable operating leases are payable as follows:

Year Ending December 31	
(Millions)	**Payments**
2015	$ 0.5
2016	0.8
2017	0.8
2018	0.6
2019	0.4
Later years	12.7
Total	$ 15.8

Note 11—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	**2014**	**2013**	**2012**
Commercial paper			
Amount outstanding at December 31 [1]	**$ 145.1**	$ 25.6	$ 95.4
Average interest rate on amounts outstanding at December 31	**0.32%**	0.14%	0.24%
Average amount outstanding during the year [2]	**$ 43.3**	$ 80.8	$ 150.2
Short-term notes payable [3]			
Average amount outstanding during the year [2]	**$ —**	$ 130.4	$ —

(1) Maturity dates ranged from January 5, 2015, through January 16, 2015.

(2) Based on daily outstanding balances during the year.

(3) Short-term notes payable related to a $200.0 million loan used for the purchase of Fox Energy Company LLC in March 2013. This loan was repaid in November 2013, and therefore no balance was outstanding at December 31, 2014, 2013, and 2012. See Note 3, Acquisition of Fox Energy Center, for more information regarding this purchase.

We manage our liquidity by maintaining adequate external financing commitments. 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:

(Millions)	Maturity	2014	2013
Revolving credit facility [1]	05/17/2014	$ —	$ 135.0
Revolving credit facility [2]	05/07/2015	**135.0**	—
Revolving credit facility	06/13/2017	**115.0**	115.0
Total short-term credit capacity		**$ 250.0**	$ 250.0
Less: commercial paper outstanding		**145.1**	25.6
Available capacity under existing agreements		**$ 104.9**	$ 224.4

(1) This credit facility was terminated and replaced with a new credit facility in May 2014.

(2) We requested approval from the PSCW to extend this facility through May 8, 2019.

Our revolving credit agreement contains financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%, excluding non-recourse debt. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

Note 12—Long-Term Debt

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

In December 2015, our 6.375% Senior Notes will mature. As a result, the $125.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at December 31, 2014.

Our First Mortgage Bonds and Senior Notes are subject to the terms and conditions of our First Mortgage Indenture. Under the terms of the Indenture, substantially all our property is pledged as collateral for these outstanding debt securities. All of these debt securities require semi-annual payments of interest. Our Senior Notes become noncollateralized if we retire all of our outstanding First Mortgage Bonds and no new mortgage indenture is put in place.

Our long-term debt obligations contain covenants related to payment of principal and interest when due and various financial reporting obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

A schedule of all principal debt payment amounts related to bond maturities, excluding those associated with long-term debt to parent, is as follows:

(Millions)	Payments
2015	$ 125.0
2016	—
2017	125.0
2018	—
2019	—
Later years	925.1
Total	$ 1,175.1

Note 13—Asset Retirement Obligations

We have asset retirement obligations primarily related to asbestos abatement at certain generation facilities, office buildings, and service centers; dismantling wind generation projects; disposal of PCB-contaminated transformers; and closure of fly-ash landfills at certain generation facilities. We establish regulatory assets and liabilities to record the differences between ongoing expense recognition under the asset retirement obligation accounting rules and the ratemaking practices for retirement costs authorized by the applicable regulators. All asset retirement obligations are recorded as other long-term liabilities on our balance sheets.

The following table shows changes to our asset retirement obligations through December 31, 2014:

(Millions)	
Asset retirement obligations at December 31, 2011	$ 18.6
Accretion	1.0
Revisions to estimated cash flows	(2.5) [(1)]
Settlements	(0.4)
Asset retirement obligations at December 31, 2012	16.7
Accretion	0.9
Revisions to estimated cash flows	0.5
Settlements	(0.1)
Asset retirement obligations at December 31, 2013	18.0
Accretion	**1.0**
Revisions to estimated cash flows	**1.5** [(2)]
Settlements	**(0.2)**
Asset retirement obligations at December 31, 2014	**$ 20.3**

(1) Revisions were made to estimated cash flows related to asset retirement obligations for the PCB-contaminated transformers primarily due to changes in estimated removal costs, estimated settlement date, and transformer quantities.

(2) Revisions were made to estimated cash flows related to asset retirement obligations for the asbestos at electric generation facilities primarily due to changes in estimated settlement dates.

Note 14—Income Taxes

Deferred Income Tax Assets and Liabilities

The principal components of deferred income tax assets and liabilities recognized on the balance sheets as of December 31 are included in the table below. Certain temporary differences are netted in the table when the offsetting amount is recorded as a regulatory asset or liability. This is consistent with regulatory treatment.

(Millions)	2014	2013
Total deferred income tax assets	**$ 4.4**	$ 3.5
Deferred income tax liabilities		
Plant-related	**591.0**	491.7
Employee benefits	**83.9**	81.0
Regulatory deferrals	**42.4**	44.4
Other	**13.0**	16.7
Total deferred income tax liabilities	**$ 730.3**	$ 633.8
Total net deferred income tax liabilities	**$ 725.9**	$ 630.3
Balance sheet presentation		
Current deferred income tax liabilities – included in other current liabilities	**$ 3.8**	$ 10.8
Long-term deferred income tax liabilities	**722.1**	619.5
Total net deferred income tax liabilities	**$ 725.9**	$ 630.3

Deferred tax credit carryforwards at December 31, 2014, included $1.7 million of alternative minimum tax credits, which can be carried forward indefinitely. Other deferred tax credit carryforwards included $1.9 million of general business credits, which have a carryback period of one year and a carryforward period of 20 years. The majority of the general business credit carryforwards will expire in 2033.

We record certain adjustments related to deferred income taxes to regulatory assets and liabilities. As the related temporary differences reverse, we prospectively refund taxes to or collect taxes from customers for which deferred taxes were recorded in prior years at rates potentially different than current rates or upon enactment of changes in tax law. The net regulatory assets for these and other regulatory tax effects totaled $32.7 million and $25.9 million at December 31, 2014, and 2013, respectively. See Note 8, Regulatory Assets and Liabilities, for more information.

Income Before Taxes

All income before taxes is domestic income for the years ended December 31, 2014, 2013, and 2012.

Provision for Income Tax Expense

The components of the provision for income taxes were as follows:

(Millions)	2014	2013	2012
Current provision			
Federal	**$ (12.8)**	$ (1.3)	$ 24.8
State	**6.7**	3.4	4.2
Total current provision	**(6.1)**	2.1	29.0
Deferred provision			
Federal	**84.3**	71.5	27.8
State	**6.6**	8.3	5.9
Total deferred provision	**90.9**	79.8	33.7
Interest	**0.2**	0.3	0.1
Investment tax credits			
Deferral	**—**	—	0.2
Amortization	**(0.3)**	(0.3)	(0.4)
Total provision for income taxes	**$ 84.7**	$ 81.9	$ 62.6

Statutory Rate Reconciliation

The following table presents a reconciliation of the difference between the effective tax rate and the amount computed by applying the statutory federal tax rate to income before taxes.

	2014		2013		2012	
(Millions, except for percentages)	Rate	Amount	Rate	Amount	Rate	Amount
Statutory federal income tax	**35.0%**	**$ 78.9**	35.0%	$ 76.9	35.0%	$ 69.1
State income taxes, net	**4.8**	**10.9**	4.8	10.5	4.4	8.7
Benefits and compensation	**(1.0)**	**(2.2)**	(0.9)	(1.9)	(3.6)	(7.2)
Federal tax credits	**—**	**—**	—	—	(3.5)	(7.0)
Other differences, net	**(1.2)**	**(2.9)**	(1.6)	(3.6)	(0.6)	(1.0)
Effective income tax	**37.6%**	**$ 84.7**	37.3%	$ 81.9	31.7%	$ 62.6

Unrecognized Tax Benefits

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

(Millions)	2014	2013	2012
Balance at January 1	**$ —**	$ 0.3	$ 0.5
Increase related to tax positions taken in prior years	**—**	0.7	—
Decrease related to tax positions taken in prior years	**—**	(0.4)	—
Decrease related to settlements	**—**	(0.6)	—
Decrease related to lapse of statutes	**—**	—	(0.2)
Balance at December 31	**$ —**	$ —	$ 0.3

We had no accrued interest and penalties related to unrecognized tax benefits at December 31, 2014, and 2013.

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2014.

We file income tax returns in the United States federal jurisdiction and in our major state operating jurisdictions on a stand-alone basis or as part of Integrys Energy Group filings.

With a few exceptions, we are no longer subject to federal income tax examinations by the IRS for years prior to 2011.

We file state tax returns based on income in our major state operating jurisdictions of Wisconsin and Michigan. We are no longer subject to state and local tax examinations for years prior to 2008. As of December 31, 2014, we were subject to examination by the Wisconsin taxing authority for tax years 2009 through 2013 and the Michigan taxing authority for tax years 2008 through 2013. During 2014, the Michigan taxing authority continued its examination of tax years 2008 through 2011, which began in 2012.

In the next 12 months, we do not expect to significantly change the amount of unrecognized tax benefits.

Note 15—Commitments and Contingencies

(a) Unconditional Purchase Obligations

We routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. We have obligations to distribute and sell electricity and natural gas to our customers and 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, 2014.

(Millions)	Date Contracts Extend Through	Total Amounts Committed	Payments Due By Period 2015	2016	2017	2018	2019	Later Years
Electric utility								
Purchased power	2029	$ 836.8	$ 122.8	$ 42.8	$ 53.3	$ 55.9	$ 57.0	$ 505.0
Coal supply and transportation	2019	162.8	55.3	31.9	32.6	31.9	11.1	—
Natural gas utility supply and transportation	2024	243.5	45.4	43.4	42.9	42.5	27.2	42.1
Total		$ 1,243.1	$ 223.5	$ 118.1	$ 128.8	$ 130.3	$ 95.3	$ 547.1

(b) Environmental Matters

Air Permitting Violation Claims

Weston and Pulliam Clean Air Act (CAA) Issues:
In November 2009, the EPA issued a Notice of Violation (NOV) to us alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. We reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the U.S. District Court (Court) in March 2013, after a public comment period. 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. We announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. We received approval from the PSCW in our 2015 rate order to defer and amortize the undepreciated book value of the retired plant associated with Pulliam 5 and 6 and Weston 1 starting with the actual retirement date in 2015 and concluding when the balance is fully amortized. See Note 6, Property, Plant, and Equipment, for more information.

We received approval from the PSCW in our 2014 and 2015 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. We also believe that additional prudently incurred costs expected after 2015 will be recoverable from customers based on past precedent with the PSCW.

The majority of the beneficial environmental projects that we proposed have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

In May 2010, we received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that we violated the CAA at the Weston and Pulliam plants. We 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, 2014. It is unknown whether the Sierra Club will take further action in the future.

Columbia and Edgewater CAA Issues:
In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric and us. The NOV alleges violations of the CAA's New Source Review requirements related to certain projects completed at those plants. We, WP&L, and Madison Gas and Electric reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. 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 our portion totaling $1.3 million, and
- our portion of a civil penalty and legal fees totaling $0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain of the Columbia and Edgewater units. As of December 31, 2014, no decision had been made on how to address this requirement. Therefore, retirement of the Columbia and Edgewater units mentioned in the Consent Decree was not considered probable.

We believe that significant costs prudently incurred as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty, will be recoverable from customers.

All of the beneficial environmental projects that we proposed have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

Weston Title V Air Permit:
In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, we 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, we also requested a modification to the construction permit for Weston 4 to remove the mercury Best Available Control Technology (BACT) emission limit requirement. This permit request was denied by the WDNR and we challenged this issue as well. At our request, the permit was modified to resolve several of the petition issues. Those issues have now been voluntarily dismissed from the case, while one new permit change was challenged and added to the case. The administrative law judge (ALJ) recently dismissed some of the petition issues relating to the averaging period and monitoring issues. In May 2014, the WDNR issued an NOV alleging that we failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System certification. The WDNR also issued a Notice of Inquiry (NOI) alleging that we failed to comply with reporting requirements related to challenged matters in the 2013 Weston Title V permit. The ALJ recently denied our request to issue a stay or confirm that a statutory stay applies to the requirements identified in the NOV and NOI. The parties are discussing a briefing schedule, but no hearing date has been set. We do not expect these matters to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule required a 40% reduction from historical baseline mercury emissions, beginning January 1, 2010, through the end of 2014. Beginning in 2015, electric generating units above 150 megawatts would have been required to further reduce mercury emissions. However, in December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which regulates emissions of mercury and other hazardous air pollutants beginning in April 2015. The State of Wisconsin recently revised the state mercury rule to be consistent with the MATS rule. Projects approved and initiated to address the State of Wisconsin mercury rule are expected to ensure compliance with the mercury limits in the MATS rule.

We were in compliance with the State of Wisconsin's mercury rule at the end of 2014. In addition, we are making progress toward compliance with the MATS rule in 2015. We estimated capital costs of approximately $9 million for our wholly owned plants to achieve the required reductions for MATS compliance, of which approximately $8 million was expended as of December 31, 2014. The capital costs are expected to be recovered in future rates.

Sulfur Dioxide and Nitrogen Oxide:
In July 2011, the EPA issued a final rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including us, challenged in the United States Court of Appeals (Court of Appeals) for the District of Columbia Circuit (D.C. Circuit). The new rule was to become effective in January 2012. However, in December 2011, the CSAPR requirements were stayed by the D.C. Circuit and a previous rule, the Clean Air Interstate Rule (CAIR), was implemented during the stay period. In August 2012, the D.C. Circuit issued their 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), and in April 2014, the Supreme Court upheld the CSAPR rule and remanded the case to the Court of Appeals for the D.C. Circuit. In October 2014, the Court of Appeals granted the EPA's request and lifted the stay on CSAPR and changed the compliance deadlines by three years, so that Phase I emissions budgets will apply in 2015 and 2016 and Phase 2 emissions budgets will apply to 2017 and beyond. We do not expect to incur significant costs to comply with either phase of CSAPR and expect to recover any future compliance costs in future rates.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule were considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they were in compliance with CAIR. This determination was updated when CSAPR was issued (CSAPR satisfied BART). Although particulate emissions also contribute to visibility impairment, the WDNR's modeling for Pulliam Unit 8, the only unit covered by BART, has shown the impairment to be so insignificant that additional capital expenditures or controls may not be warranted.

Clean Water Act Rule

In August 2014, the EPA issued a final Clean Water Act rule, which established requirements under Section 316(b) to regulate water intake structures at industrial facilities that use large volumes of surface water as cooling water. The new rule became effective in October 2014 and has been challenged by a number of parties. The cases have been consolidated and will be heard in the United States Court of Appeals for the Second Circuit. To the extent that the rule is upheld, we will comply with the rule on the timeline required under the regulation. We will evaluate the impact of compliance by conducting the studies required by the rule at our facilities. We anticipate that the timing for compliance will be incorporated into future wastewater discharge permit renewals. We do not expect to incur significant costs to comply with the Clean Water Act rule as our Weston plants are already equipped with cooling towers that assist with meeting these new requirements. We expect to recover any future compliance costs in future rates.

Manufactured Gas Plant Remediation

We operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, we are required to undertake remedial action with respect to some of these materials. We are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction 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.

We are responsible for the environmental remediation of ten sites, of which seven have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. Our balance sheet includes liabilities of $86.3 million that we have estimated and accrued for as of December 31, 2014, for future undiscounted investigation and cleanup costs for all sites. We may adjust these estimates in the future due to remedial technology, regulatory requirements, remedy determinations, and any claims of natural resource damages. As of December 31, 2014, cash expenditures for environmental remediation not yet recovered in rates were $16.0 million. Our balance sheet also includes a regulatory asset of $102.3 million at December 31, 2014, which is net of insurance recoveries, related to the expected recovery through rates of both cash expenditures and estimated future expenditures. Under current PSCW policies, we may not recover carrying costs associated with the cleanup expenditures.

Management believes that any costs incurred for environmental activities relating to former manufactured gas plant operations that are not recoverable through contributions from other entities or from insurance carriers have been prudently incurred and are, therefore, recoverable through rates. Accordingly, we do not expect these costs to have a material impact on our financial statements. However, any changes in the approved rate mechanisms for recovery of these costs, or any adverse conclusions by the PSCW or the MPSC with respect to the prudence of costs actually incurred, could materially affect recovery of such costs through rates.

Note 16—Employee Benefit Plans

Defined Benefit Plans

We participate in the Integrys Energy Group Retirement Plan, a noncontributory, qualified pension plan sponsored by IBS. We are responsible for our share of the plan assets and obligations. We serve as plan sponsor and administrator for certain other postretirement benefit plans. The benefits are funded through irrevocable trusts, as allowed for income tax purposes. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets and obligations. Integrys Energy Group also offers medical, dental, and life insurance benefits to our active employees and their dependents. We expense the allocated costs of these benefits as incurred.

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. In March 2014, we remeasured the obligations of certain other postretirement benefit plans as a result of a plan design change to move participants age 65 and older to a Medicare Advantage plan starting January 1, 2015.

The following tables provide a reconciliation of the changes in our share of the plans' benefit obligations and fair value of assets:

	Pension Benefits		Other Benefits	
(Millions)	**2014**	**2013**	**2014**	**2013**
Change in benefit obligation				
Obligation at January 1	**$ 717.5**	$ 772.6	**$ 292.7**	$ 328.5
Service cost	**8.6**	10.8	**7.7**	10.6
Interest cost	**34.4**	30.6	**11.5**	13.4
Plan amendments	**—**	—	**(74.4)**	0.1
Transfer to affiliates	**(12.1)**	(6.6)	**—**	—
Actuarial loss (gain), net	**73.0**	(63.6)	**24.0**	(51.4)
Participant contributions	**—**	—	**0.5**	0.6
Benefit payments	**(29.6)**	(26.3)	**(10.4)**	(10.0)
Federal subsidy on benefits paid	**—**	—	**0.9**	0.9
Obligation at December 31	**$ 791.8**	$ 717.5	**$ 252.5**	$ 292.7
Change in fair value of plan assets				
Fair value of plan assets at January 1	**$ 839.1**	$ 719.6	**$ 236.5**	$ 213.7
Actual return on plan assets	**53.1**	112.1	**7.4**	29.0
Employer contributions	**46.9**	40.3	**2.6**	3.2
Participant contributions	**—**	—	**0.5**	0.6
Benefit payments	**(29.6)**	(26.3)	**(10.4)**	(10.0)
Transfer to affiliates	**(12.1)**	(6.6)	**—**	—
Fair value of plan assets at December 31	**$ 897.4**	$ 839.1	**$ 236.6**	$ 236.5
Funded status at December 31	**$ 105.6**	$ 121.6	**$ (15.9)**	$ (56.2)

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

	Pension Benefits		Other Benefits	
(Millions)	**2014**	**2013**	**2014**	**2013**
Long-term assets	**$ 128.9**	$ 145.1	**$ —**	$ —
Current liabilities	**1.5**	3.1	**0.1**	0.2
Long-term liabilities	**21.8**	20.4	**15.8**	56.0
Total net assets (liabilities)	**$ 105.6**	$ 121.6	**$ (15.9)**	$ (56.2)

The accumulated benefit obligation for the defined benefit pension plans was $717.4 million and $658.3 million at December 31, 2014, and 2013, respectively.

The following table shows information for qualified pension plans with an accumulated benefit obligation in excess of plan assets. There were no plan assets related to these pension plans. Amounts presented are as of December 31:

(Millions)	**2014**	**2013**
Projected benefit obligation	**$ 23.3**	$ 23.5
Accumulated benefit obligation	**21.5**	21.8

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

	Pension Benefits		Other Benefits	
(Millions)	**2014**	**2013**	**2014**	**2013**
Net regulatory assets				
Net actuarial loss	**$ 178.7**	$ 110.2	**$ 41.0**	$ 11.5
Prior service cost (credit)	**1.8**	2.4	**(78.3)**	(12.0)
Total	**$ 180.5**	$ 112.6	**$ (37.3)**	$ (0.5)

The following table shows the estimated amounts in regulatory assets that will be amortized into net periodic benefit cost during 2015:

(Millions)	Pension Benefits	Other Benefits
Net actuarial loss	$ 19.6	$ 4.2
Prior service cost (credit)	0.2	(9.3)
Total 2015 - estimated amortization	$ 19.8	$ (5.1)

The following table shows the components of net periodic benefit cost (including amounts capitalized to our balance sheets) for our benefit plans:

	Pension Benefits			Other Benefits		
(Millions)	2014	2013	2012	2014	2013	2012
Service cost	**$ 8.6**	$ 10.8	$ 12.8	**$ 7.7**	$ 10.6	$ 8.5
Interest cost	**34.4**	30.6	34.0	**11.5**	13.4	15.1
Expected return on plan assets	**(64.1)**	(57.2)	(55.4)	**(16.0)**	(14.8)	(14.6)
Loss on plan settlement	**0.4**	—	—	**—**	—	—
Amortization of transition obligation	**—**	—	—	**—**	—	0.2
Amortization of prior service cost (credit)	**0.6**	3.6	4.5	**(8.0)**	(2.1)	(3.0)
Amortization of net actuarial loss	**15.0**	24.0	14.9	**2.8**	7.5	5.7
Net periodic benefit cost	**$ (5.1)**	$ 11.8	$ 10.8	**$ (2.0)**	$ 14.6	$ 11.9

Assumptions – Pension and Other Postretirement Benefit Plans

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

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	**4.08%**	4.92%	**4.11%**	4.98%
Rate of compensation increase	**4.23%**	4.25%	**N/A**	N/A
Assumed medical cost trend rate	**N/A**	N/A	**6.00%**	6.50%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2023**	2019
Assumed dental cost trend rate	**N/A**	N/A	**5.00%**	5.00%

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

	Pension Benefits		
	2014	2013	2012
Discount rate	**4.92%**	4.07%	5.10%
Expected return on assets	**8.00%**	8.00%	8.25%
Rate of compensation increase	**4.25%**	4.26%	4.26%

	Other Benefits		
	2014	2013	2012
Discount rate	**4.78%**	4.01%	5.04%
Expected return on assets	**8.00%**	8.00%	8.25%
Assumed medical cost trend rate (under age 65)	**6.50%**	7.00%	7.00%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2019**	2019	2016
Assumed medical cost trend rate (over age 65)	**6.50%**	7.00%	7.50%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2019**	2019	2016
Assumed dental cost trend rate	**5.00%**	5.00%	5.00%

We establish our expected return on assets assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. For 2015, the expected return on assets assumption for the plans is 7.75%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for the health care plans. For the year ended December 31, 2014, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

	One-Percentage-Point	
(Millions)	Increase	Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 3.3	$ (2.6)
Effect on the health care component of the accumulated postretirement benefit obligation	34.4	(33.9)

Pension and Other Postretirement Benefit Plan Assets

Integrys Energy Group's investment policy includes various guidelines and procedures designed to ensure assets are invested in an appropriate manner to meet expected future benefits to be earned by participants. The investment guidelines consider a broad range of economic conditions. The policy is established and administered in a manner that is compliant at all times with applicable regulations.

Central to the policy are target allocation ranges by major asset categories. The objectives of the target allocations are to maintain investment portfolios that diversify risk through prudent asset allocation parameters and to achieve asset returns that meet or exceed the plans' actuarial assumptions and that are competitive with like instruments employing similar investment strategies. The portfolio diversification provides protection against significant concentrations of risk in the plan assets. In 2014, the pension plan target asset allocation was 70% equity securities and 30% fixed income securities. In December 2014, we changed the pension plan target asset allocation to 60% equity securities and 40% fixed income securities for 2015. The target asset allocation for other postretirement benefit plans that have significant assets is 70% equity securities and 30% fixed income securities. Equity securities primarily include investments in large-cap and small-cap companies. Fixed income securities primarily include corporate bonds of companies from diversified industries, United States government securities, and mortgage-backed securities.

The Board of Directors of Integrys Energy Group established the Employee Benefits Administrator Committee (composed of members of Integrys Energy Group and its subsidiaries' management) to manage the operations and administration of all benefit plans and trusts. The committee monitors the asset allocation, and the portfolio is rebalanced when necessary.

Pension and other postretirement benefit plan investments are recorded at fair value. See Note 1(t), Fair Value, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

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

	December 31, 2014							
	Pension Plan Assets				Other Benefit Plan Assets			
(Millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 24.9	$ —	$ 24.9	$ 4.6	$ 1.6	$ —	$ 6.2
Equity securities:								
United States equity	53.6	197.8	—	251.4	14.8	62.4	—	77.2
International equity	54.4	225.9	—	280.3	17.6	65.4	—	83.0
Fixed income securities:								
United States government	41.3	12.7	—	54.0	61.3	—	—	61.3
Foreign government	—	12.1	—	12.1	—	—	—	—
Corporate debt	—	250.5	—	250.5	—	—	—	—
Other	—	31.5	—	31.5	0.2	—	—	0.2
	149.3	755.4	—	904.7	98.5	129.4	—	227.9
401(h) other benefit plan assets invested as pension assets [1]	(1.5)	(7.3)	—	(8.8)	1.5	7.3	—	8.8
Total [2]	$ 147.8	$ 748.1	$ —	$ 895.9	$ 100.0	$ 136.7	$ —	$ 236.7

(1) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(2) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

(Millions)	December 31, 2013 Pension Plan Assets Level 1	Level 2	Level 3	Total	Other Benefit Plan Assets Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ 1.1	$ 19.7	$ —	$ 20.8	$ —	$ 2.3	$ —	$ 2.3
Equity securities:								
United States equity	54.1	239.9	—	294.0	14.2	66.5	—	80.7
International equity	61.5	231.3	—	292.8	16.7	63.3	—	80.0
Fixed income securities:								
United States government	—	50.4	—	50.4	65.0	0.6	—	65.6
Foreign government	—	9.1	1.3	10.4	—	—	—	—
Corporate debt	—	134.8	0.7	135.5	—	—	—	—
Asset-backed securities	—	33.3	—	33.3	—	—	—	—
Other	—	9.4	—	9.4	(0.1)	—	—	(0.1)
	116.7	727.9	2.0	846.6	95.8	132.7	—	228.5
401(h) other benefit plan assets invested as pension assets [1]	(1.1)	(7.1)	—	(8.2)	1.1	7.1	—	8.2
Total [2]	$ 115.6	$ 720.8	$ 2.0	$ 838.4	$ 96.9	$ 139.8	$ —	$ 236.7

(1) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(2) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

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

(Millions)	Foreign Government Debt	Corporate Debt	Total
Beginning balance at January 1, 2014	**$ 1.3**	**$ 0.7**	**$ 2.0**
Net realized and unrealized gains	**0.1**	**0.1**	**0.2**
Sales	**(1.4)**	**(0.8)**	**(2.2)**
Ending balance at December 31, 2014	**$ —**	**$ —**	**$ —**
Net unrealized gains (losses) related to assets still held at the end of the period	**$ —**	**$ —**	**$ —**

(Millions)	Foreign Government Debt	Corporate Debt	Total
Beginning balance at January 1, 2013	$ 2.2	$ 0.5	$ 2.7
Net realized and unrealized losses	(0.1)	(0.2)	(0.3)
Purchases	0.3	—	0.3
Sales	(1.1)	(0.2)	(1.3)
Transfers into Level 3	—	0.8	0.8
Transfers out of Level 3	$ —	$ (0.2)	(0.2)
Ending balance at December 31, 2013	$ 1.3	$ 0.7	$ 2.0
Net unrealized losses related to assets still held at the end of the period	$ (0.1)	$ (0.2)	$ (0.3)

Cash Flows Related to Pension and Other Postretirement Benefit Plans

Our funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. We expect to contribute $1.5 million to the pension plans and $1.2 million to other postretirement benefit plans in 2015, dependent on various factors affecting us, including our liquidity position and tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and other postretirement benefits.

(Millions)	Pension Benefits	Other Benefits
2015	$ 41.2	$ 9.4
2016	42.3	10.0
2017	44.3	10.9
2018	44.1	11.7
2019	45.6	12.5
2020 through 2024	224.3	73.6

Defined Contribution Benefit Plans

Integrys Energy Group maintains a 401(k) Savings Plan for substantially all of our full-time employees. A percentage of employee contributions are matched through an employee stock ownership plan (ESOP) contribution up to certain limits. Certain union employees receive a contribution to their ESOP account regardless of their participation in the 401(k) Savings Plan. Certain employees participate in a defined contribution pension plan, in which certain amounts are contributed to an employee's account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $8.6 million in 2014, $8.2 million in 2013, and $5.5 million in 2012.

Integrys Energy Group maintains deferred compensation plans that enable certain key employees, including some who are our employees, to defer payment of a portion of their compensation on a pre-tax basis. Compensation is generally deferred in the form of cash and is indexed to certain investment options or Integrys Energy Group common stock. The deemed dividends paid on the common stock are automatically reinvested.

The deferred compensation arrangements for which distributions are made solely in Integrys Energy Group common stock are classified as an equity instrument on the balance sheets. Changes in the fair value of this portion of the deferred compensation obligation are not recognized. The deferred compensation obligation classified as an equity instrument was $7.0 million at December 31, 2014, and $8.0 million at December 31, 2013.

The portion of the deferred compensation obligation that is indexed to various investment options and allows for distributions in cash is classified as a liability on the balance sheets. The liability is adjusted, with a charge or credit to expense, to reflect changes in the fair value of the deferred compensation obligation. The obligation classified within other long-term liabilities was $15.5 million at December 31, 2014, and $15.1 million at December 31, 2013. The costs incurred under this arrangement were $1.9 million in 2014, $1.5 million in 2013, and $1.1 million in 2012.

Note 17—Preferred Stock

We have 1,000,000 authorized shares of preferred stock with no mandatory redemption and a $100 par value. Outstanding shares were as follows at December 31:

(Millions, except share amounts)	2014		2013	
Series	Shares Outstanding	Carrying Value	Shares Outstanding	Carrying Value
5.00%	**131,916**	**$ 13.2**	131,916	$ 13.2
5.04%	**29,983**	**3.0**	29,983	3.0
5.08%	**49,983**	**5.0**	49,983	5.0
6.76%	**150,000**	**15.0**	150,000	15.0
6.88%	**150,000**	**15.0**	150,000	15.0
Total	**511,882**	**$ 51.2**	511,882	$ 51.2

All shares of preferred stock of all series are of equal rank except as to dividend rates and redemption terms. Payment of dividends from any earned surplus or other available surplus is not restricted by the terms of any indenture or other undertaking by us. Each series of outstanding preferred stock is redeemable in whole or in part at our option at any time on 30 days' notice at the respective redemption prices. We may not redeem less than all, nor purchase any, of our preferred stock during the existence of any dividend default.

In the event of our dissolution or liquidation, the holders of preferred stock are entitled to receive (a) the par value of their preferred stock out of the corporate assets other than profits before any of such assets are paid or distributed to the holders of common stock and (b) the amount of dividends accumulated and unpaid on their preferred stock out of the surplus or net profits before any of such surplus or net profits are paid to the holders of common stock. Thereafter, the remainder of the corporate assets, surplus, and net profits would be paid to the holders of common stock.

The preferred stock has no pre-emptive, subscription, or conversion rights, and has no sinking fund provisions.

Note 18—Common Equity

Various laws, regulations, and financial covenants impose restrictions on our ability to pay dividends to the sole holder of our common stock, Integrys Energy Group.

The PSCW allows us to pay dividends on our common stock of no more than 103% of the previous year's common stock dividend. We may return capital to Integrys Energy Group if our average financial common equity ratio is at least 51% on a calendar year basis. We must obtain PSCW approval if a return of capital would cause our average financial common equity ratio to fall below this level. Integrys Energy Group's right to receive dividends on our common stock is also subject to the prior rights of our preferred shareholders and to provisions in our restated articles of incorporation, which limit the amount of common stock dividends that we may pay if our common stock and common stock surplus accounts constitute less than 25% of our total capitalization.

Our short-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.

As of December 31, 2014, total restricted retained earnings were $521.8 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $30.8 million at December 31, 2014.

Except for the restrictions described above and subject to applicable law, we do not have any other significant dividend restrictions.

Integrys Energy Group may provide equity contributions to us or request a return of capital from us in order to maintain utility common equity levels consistent with those allowed by the PSCW. Wisconsin law prohibits us from making loans to or guaranteeing obligations of Integrys Energy Group or its other subsidiaries. During the year ended December 31, 2014, we received $55.0 million of equity contributions from Integrys Energy Group and paid common stock dividends of $111.8 million to Integrys Energy Group.

Note 19—Guarantees

The following table shows our outstanding guarantees:

		Expiration	
(Millions)	**Total Amounts Committed at December 31, 2014**	**Less Than 1 Year**	**Over 1 Year**
Standby letters of credit [1]	**$ 0.1**	$ 0.1	$ —
Surety bonds[2]	**0.6**	0.6	—
Other guarantee[3]	**0.5**	—	0.5
Total guarantees	**$ 1.2**	$ 0.7	$ 0.5

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

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

(3) Issued for workers compensation coverage in Wisconsin and Michigan. This amount is not reflected on our balance sheets.

Note 20—Stock-Based Compensation

The following table reflects the stock-based compensation expense and the related deferred tax benefit recognized in income for the years ended December 31:

(Millions)	**2014**	**2013**	**2012**
Stock options	**$ 1.0**	$ 0.7	$ 0.7
Performance stock rights	**6.3**	1.1	1.9
Restricted share units	**3.8**	3.4	3.4
Total stock-based compensation expense	**$ 11.1**	$ 5.2	$ 6.0
Deferred income tax benefit	**$ 4.4**	$ 2.1	$ 2.4

No stock-based compensation cost was capitalized during 2014, 2013, and 2012.

Stock Options

The following table shows the weighted-average fair values per stock option granted along with the assumptions incorporated into the binomial lattice valuation models:

	2014 Grant	2013 Grant	2012 Grant
Weighted-average fair value per option	**$6.70**	$6.03	$6.30
Expected term	**8 years**	5 years	5 years
Risk-free interest rate	**0.12% – 2.88%**	0.18% – 2.11%	0.17% – 2.18%
Expected dividend yield	**5.28%**	5.33%	5.28%
Expected volatility	**18%**	24%	25%

A summary of stock option activity for 2014, and information related to outstanding and exercisable stock options at December 31, 2014, is presented below:

	Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2013	49,993	$ 53.03		
Granted	**13,890**	**55.23**		
Exercised	**(58,169)**	**53.44**		
Outstanding at December 31, 2014	**5,714**	**$ 54.18**	**7.5**	**$ 0.1**
Exercisable at December 31, 2014	**—**	**N/A**	**N/A**	**N/A**

The aggregate intrinsic value for 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 all exercised their options on December 31, 2014. This is calculated as the difference between Integrys Energy Group's closing stock price on December 31, 2014, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during 2014 was $1.0 million, and was not significant during 2013 and 2012. The actual tax benefit realized for the tax deductions from these option exercises was not significant.

Due to the accelerated vesting of all unvested stock options held by active employees in October 2014, all compensation expense related to outstanding stock options has been recognized at December 31, 2014.

Performance Stock Rights

The table below reflects the assumptions used in the Monte Carlo valuation models to estimate the fair value of the outstanding performance stock rights at December 31:

	2014	2013	2012
Risk-free interest rate	**0.21% – 0.63%**	0.13% – 1.27%	0.17% – 1.27%
Expected dividend yield	**5.25% – 5.33%**	5.28% – 5.34%	5.18% – 5.34%
Expected volatility	**18% – 22%**	15% – 36%	14% – 36%

A summary of the 2014 activity related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value [(2)]
Outstanding at December 31, 2013	5,561	$ 45.16
Granted	**1,113**	**44.28**
Award modifications	**2,295**	**85.09**
Distributed [(1)]	**(2,235)**	**75.02**
Adjustment for estimated payout and shares not distributed [(1)]	**(2,831)**	**46.32**
Outstanding at December 31, 2014	**3,903**	**$ 58.03**

(1) No shares of Integrys Energy Group common stock were distributed for performance stock rights with a performance period ending December 31, 2013, because the performance percentage was below the threshold payout level. In October 2014, Integrys Energy Group's Board of Directors approved the acceleration of a portion of the estimated distribution for those performance stock rights held by active employees with a performance period ending December 31, 2014. This distribution was made in December 2014.

(2) Reflects the weighted-average fair value used to measure equity awards. Equity awards are measured using the grant date fair value or the fair value on the modification date.

The weighted-average grant date fair value of performance stock rights awarded during 2014, 2013, and 2012, was $44.28, $48.50, and $52.70 per performance stock right, respectively.

A summary of the 2014 activity related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2013	9,222
Granted	**4,440**
Award modifications	**(2,295)**
Distributed *	**(1,240)**
Adjustment for estimated payout and shares not distributed *	**(93)**
Outstanding at December 31, 2014	**10,034**

* No shares of Integrys Energy Group common stock were distributed for performance stock rights with a performance period ending December 31, 2013, because the performance percentage was below the threshold payout level. In October 2014, Integrys Energy Group's Board of Directors approved the acceleration of a portion of the estimated distribution for those performance stock rights held by active employees with a performance period ending December 31, 2014. This distribution was made in December 2014.

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of December 31, 2014, was $121.26 per performance stock right.

As of December 31, 2014, $2.0 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.6 years.

The total intrinsic value of performance stock rights distributed during 2014, 2013, and 2012, was not significant.

Restricted Share Units

A summary of the 2014 activity related to all restricted share unit awards (equity and liability awards) is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2013	67,741	$ 52.06
Granted	**28,725**	**55.23**
Dividend equivalents	**2,875**	**54.45**
Vested and released	**(28,325)**	**49.50**
Transfers	**332**	**54.55**
Forfeited	**(804)**	**54.64**
Outstanding at December 31, 2014	**70,544**	**$ 54.46**

As of December 31, 2014, $3.5 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.3 years.

The total intrinsic value of restricted share unit awards vested and released during 2014, 2013, and 2012, was $1.5 million, $1.6 million, and $1.5 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted share units during 2014, 2013, and 2012, was not significant.

The weighted-average grant date fair value of restricted share units awarded during 2014, 2013, and 2012 was $55.23, $56.05, and $53.24 per unit, respectively.

Note 21—Fair Value

Fair Value Measurements

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

	December 31, 2014			
(Millions)	Level 1	Level 2	Level 3	Total
Risk management assets				
Natural gas contracts	**$ —**	**$ 0.1**	**$ —**	**$ 0.1**
Financial transmission rights (FTRs)	**—**	**—**	**2.2**	**2.2**
Total	**$ —**	**$ 0.1**	**$ 2.2**	**$ 2.3**
Risk management liabilities				
Natural gas contracts	**$ 2.2**	**$ —**	**$ —**	**$ 2.2**
FTRs	**—**	**—**	**0.3**	**0.3**
Petroleum product contracts	**1.1**	**—**	**—**	**1.1**
Coal contracts	**—**	**1.2**	**2.2**	**3.4**
Total	**$ 3.3**	**$ 1.2**	**$ 2.5**	**$ 7.0**

	December 31, 2013			
(Millions)	Level 1	Level 2	Level 3	Total
Risk management assets				
Natural gas contracts	$ 0.6	$ —	$ —	$ 0.6
FTRs	—	—	1.5	1.5
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	0.2	0.2
Total	$ 0.7	$ —	$ 1.7	$ 2.4
Risk management liabilities				
Natural gas contracts	$ 0.1	$ —	$ —	$ 0.1
FTRs	—	—	0.3	0.3
Coal contracts	—	—	2.7	2.7
Total	$ 0.1	$ —	$ 3.0	$ 3.1

The risk management assets and liabilities listed in the tables above include NYMEX futures and options, financial contracts used to manage transmission congestion costs in the MISO market, and physical commodity contracts. See Note 5, Risk Management Activities, for more information on our derivative instruments.

During 2014, a $1.2 million risk management liability related to certain coal contracts transferred from Level 3 to Level 2 of the fair value hierarchy. There were no transfers between the levels of the fair value hierarchy during 2013.

The significant unobservable inputs used in the valuations that resulted in categorization within Level 3 were as follows at December 31, 2014. The amounts listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a derivative to be classified as Level 3.

	Fair Value *(Millions)*				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
FTRs	**$ 2.2**	**$ 0.3**	Market-based	Forward market prices ($/megawatt-month) (1)	**$188.16**
Coal contract	**—**	**2.2**	Market-based	Forward market prices ($/ton) (2)	**$10.89 — $13.60**

(1) Represents forward market prices developed using historical cleared pricing data from MISO.

(2) Represents third-party forward market pricing.

Significant changes in historical settlement prices and forward coal prices would result in a directionally similar significant change in fair value.

The following tables set forth a reconciliation of changes in the fair value of items categorized as Level 3 measurements:

	2014		
(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of period	**$ 1.2**	**$ (2.5)**	**$ (1.3)**
Net realized gains included in earnings	**0.2**	**—**	**0.2**
Net unrealized gains recorded as regulatory assets or liabilities	**0.4**	**(1.6)**	**(1.2)**
Purchases	**4.3**	**—**	**4.3**
Settlements	**(4.2)**	**0.7**	**(3.5)**
Net transfers out of Level 3	**—**	**1.2**	**1.2**
Balance at the end of period	**$ 1.9**	**$ (2.2)**	**$ (0.3)**

	2013		
(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of period	$ 1.1	$ (6.5)	$ (5.4)
Net realized gains included in earnings	3.0	—	3.0
Net unrealized (losses) gains recorded as regulatory assets or liabilities	(0.1)	0.4	0.3
Purchases	3.2	—	3.2
Sales	(0.2)	—	(0.2)
Settlements	(5.8)	3.6	(2.2)
Balance at the end of period	$ 1.2	$ (2.5)	$ (1.3)

	2012		
(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of period	$ 1.2	$ (6.9)	$ (5.7)
Net realized gains included in earnings	1.8	—	1.8
Net unrealized losses (gains) recorded as regulatory assets or liabilities	(0.1)	5.8	5.7
Purchases	2.8	—	2.8
Sales	(0.1)	—	(0.1)
Settlements	(4.5)	(5.4)	(9.9)
Balance at the end of period	$ 1.1	$ (6.5)	$ (5.4)

Unrealized gains and losses on FTRs and coal contracts are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on FTRs, as well as the related transmission congestion costs, are recorded in cost of fuel, natural gas, and purchased power on the statements of income.

Fair Value of Financial Instruments

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

	December 31, 2014		December 31, 2013	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	**$ 1,174.5**	**$ 1,286.2**	$ 1,174.5	$ 1,176.5
Long-term debt to parent	**5.4**	**5.7**	6.3	7.1
Preferred stock	**51.2**	**52.0**	51.2	61.4

Note 22—Regulatory Environment

Wisconsin

2015 Rates

In December 2014, the PSCW issued a final written order, effective January 1, 2015. It authorized a net retail electric rate increase of $24.6 million and a net retail natural gas rate decrease of $15.4 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.28% in our regulatory capital structure. The PSCW approved a change in rate design for us, which includes higher fixed charges to better match the related fixed costs of providing service. The retail electric rate increase included recovery of 2013 deferred costs related to the acquisition of the Fox Energy Center. We also received approval from the PSCW to defer and amortize the undepreciated book value of the retired plant associated with Pulliam 5 and 6 and Weston 1 starting with the actual retirement date in 2015 and concluding when the balance is fully amortized. See Note 15, Commitments and Contingencies, for more information. In addition, the PSCW will allow escrow treatment for ATC and MISO network transmission expenses for 2015 and 2016. This allows us to defer as a regulatory asset or liability the differences between actual transmission expenses and those included in rates. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a two percent tolerance window. The retail natural gas rate decrease included a refund to customers in 2015 of the 2013 decoupling over-collections.

2014 Rates

In December 2013, the PSCW issued a final written order, effective January 1, 2014. It authorized a net retail electric rate decrease of $12.8 million and a net retail natural gas rate increase of $4.0 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.14% in our regulatory capital structure. The retail electric rate impact consisted of a rate increase, including recovery of the difference between the 2012 fuel refund and the 2013 rate increase discussed below, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. The retail natural gas rate impact consisted of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 related to the Pulliam and Weston sites. See Note 15, Commitments and Contingencies, for more information. Additionally, the order required us to terminate our existing decoupling mechanism, beginning January 1, 2014.

2013 Rates

In December 2012, the PSCW issued a final written order, effective January 1, 2013. The order included a $28.5 million retail electric rate increase, partially offset by the actual 2012 fuel refund of $20.5 million. The difference between the 2012 fuel refund and the rate increase was deferred for recovery in 2014 rates. As a result, there was no change to customers' 2013 retail electric rates. The order also included a $3.4 million retail natural gas rate decrease. The order reflected a 10.30% return on common equity and a common equity ratio of 51.61% in our regulatory capital structure. The rate changes included deferrals of $7.3 million for retail electric and $2.1 million for retail natural gas of pension and other employee benefit costs that are being recovered in 2014 rates. In addition, we were authorized recovery of $5.9 million related to income tax amounts previously expensed due to the Federal Health Care Reform Act. As a result, this amount was recorded as a regulatory asset in 2012, and recovery from customers began in 2013. The order also authorized the recovery of direct Cross State Air Pollution Rule costs incurred through the end of 2012. Lastly, the order authorized us to switch from production tax credits to Section 1603 Grants for the Crane Creek wind project.

A decoupling mechanism for natural gas and electric residential and small commercial and industrial customers was approved on a pilot basis as part of the order. The mechanism was based on total rate case-approved margins, rather than being calculated on a per-customer basis. The mechanism did not cover all customer classes, and it included an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers were subject to these caps.

Michigan

2015 Rate Case

In October 2014, we filed an application with the MPSC to increase retail electric rates $5.7 million, with interim rates expected to be effective in April 2015. Our request reflected a 10.60% return on common equity and a target common equity ratio of 50.48% in our regulatory capital structure. The proposed retail electric rate increase was primarily driven by the 2013 acquisition of the Fox Energy Center as well as other capital investments associated with the Crane Creek wind farm and environmental upgrades at generating plants. Expenses are expected to increase for line clearance, customer relations, uncollectible expenses, injuries and damages, and general inflation. The proposal included annual rate increases to be implemented over a three-year period.

Note 23—Miscellaneous Income

Total miscellaneous income was as follows:

(Millions)	**2014**	**2013**	**2012**
Equity portion of AFUDC	**$ 11.0**	$ 9.9	$ 2.6
Earnings from equity method investments	**10.3**	11.3	11.0
Key executive life insurance for retired employees	**1.6**	1.1	1.1
Coal transportation services	**1.0**	1.2	0.9
Other	**0.5**	—	0.1
Total miscellaneous income	**$ 24.4**	$ 23.5	$ 15.7

Note 24—Segments of Business

At December 31, 2014, we reported three segments. We manage our reportable segments separately due to their different operating and regulatory environments. Our principal business segments are our electric utility operations and the natural gas utility operations. The other segment includes nonutility activities, as well as equity earnings from our investments in WRPC and WPS Investments, LLC, which holds an interest in ATC. All of our operations and assets are located within the United States. The table below presents information related to our reportable segments:

2014 *(Millions)*	Regulated Utilities					
	Electric Utility	**Natural Gas Utility**	**Total Utility**	**Other**	**Reconciling Eliminations**	**WPS Consolidated**
Income Statement						
External revenues	**$ 1,222.4**	**$ 459.9**	**$ 1,682.3**	**$ —**	**$ —**	**$ 1,682.3**
Intersegment revenues	**—**	**12.4**	**12.4**	**1.4**	**(13.8)**	**—**
Depreciation and amortization expense	**97.4**	**16.2**	**113.6**	**0.6**	**(0.5)**	**113.7**
Miscellaneous income	**11.1**	**0.4**	**11.5**	**12.9**	**—**	**24.4**
Interest expense	**45.1**	**10.2**	**55.3**	**2.1**	**—**	**57.4**
Provision for income taxes	**64.1**	**16.6**	**80.7**	**4.0**	**—**	**84.7**
Preferred stock dividend requirements	**(2.6)**	**(0.5)**	**(3.1)**	**—**	**—**	**(3.1)**
Net income attributed to common shareholder	**104.7**	**25.7**	**130.4**	**7.2**	**—**	**137.6**
Total assets	**3,511.0**	**682.3**	**4,193.3**	**85.4**	**—**	**4,278.7**
Cash expenditures for long-lived assets	**279.3**	**49.8**	**329.1**	**—**	**—**	**329.1**

2013 *(Millions)*	Regulated Utilities					
	Electric Utility	**Natural Gas Utility**	**Total Utility**	**Other**	**Reconciling Eliminations**	**WPS Consolidated**
Income Statement						
External revenues	$ 1,241.8	$ 337.5	$ 1,579.3	$ —	$ —	$ 1,579.3
Intersegment revenues	—	10.9	10.9	1.4	(12.3)	—
Depreciation and amortization expense	90.5	15.6	106.1	0.6	(0.5)	106.2
Miscellaneous income	9.9	0.2	10.1	13.4	—	23.5
Interest expense	33.0	8.5	41.5	2.2	—	43.7
Provision for income taxes	61.6	16.1	77.7	4.2	—	81.9
Preferred stock dividend requirements	(2.5)	(0.6)	(3.1)	—	—	(3.1)
Net income attributed to common shareholder	102.3	25.0	127.3	7.5	—	134.8
Total assets	3,241.8	633.8	3,875.6	85.7	—	3,961.3
Cash expenditures for long-lived assets	595.5	37.7	633.2	—	—	633.2

2012 *(Millions)*	Regulated Utilities					
	Electric Utility	**Natural Gas Utility**	**Total Utility**	**Other**	**Reconciling Eliminations**	**WPS Consolidated**
Income Statement						
External revenues	$ 1,212.0	$ 287.2	$ 1,499.2	$ —	$ —	$ 1,499.2
Intersegment revenues	—	9.2	9.2	1.4	(10.6)	—
Depreciation and amortization expense	81.1	15.0	96.1	0.6	(0.5)	96.2
Miscellaneous income	2.6	0.1	2.7	13.0	—	15.7
Interest expense	32.4	7.9	40.3	2.2	—	42.5
Provision for income taxes	44.6	14.5	59.1	3.5	—	62.6
Preferred stock dividend requirements	(2.5)	(0.6)	(3.1)	—	—	(3.1)
Net income attributed to common shareholder	99.1	24.9	124.0	7.7	—	131.7
Total assets	2,747.5	668.2	3,415.7	106.2	—	3,521.9
Cash expenditures for long-lived assets	149.4	30.1	179.5	—	—	179.5

Note 25—Related Party Transactions

We and our subsidiary, WPS Leasing, routinely enter into transactions with related parties, including Integrys Energy Group, its subsidiaries, and other entities in which we have material interests.

We provide and receive services, property, and other items of value to and from our parent, Integrys Energy Group, and other subsidiaries of Integrys Energy Group. Effective January 1, 2014, after approval by the PSCW and other state commissions, a new affiliated interest agreement (Non-IBS AIA) went into effect and replaced certain prior agreements. It governs the provision and receipt of services by Integrys Energy Group subsidiaries, except that IBS will continue to provide services only under the existing IBS affiliated interest agreement (IBS AIA). Services under the Non-IBS AIA are subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary are priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary are priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary are priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to IBS are priced at cost.

IBS provides 15 categories of services (including financial, human resource, and administrative services) to us pursuant to the IBS AIA, which has been approved, or from which we have been granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by FERC regulations for centralized service companies, IBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the IBS AIA. Other modifications or amendments to the IBS AIA would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

We provide services to ATC for its transmission facilities under several agreements approved by the PSCW. Services are billed to ATC under this agreement at our fully allocated cost.

We provide services to WRPC under an operating agreement approved by the PSCW. We are also under a service agreement with WRPC under which either party may be a service provider. Services are billed to WRPC under these agreements at our fully allocated cost.

The table below includes information summarizing transactions entered into with related parties as of:

(Millions)	December 31, 2014	December 31, 2013
Notes payable *		
Integrys Energy Group	**$ 5.4**	$ 6.3
Accounts Payable		
ATC	**8.2**	10.4
Liability related to income tax allocation		
Integrys Energy Group	**6.1**	6.7

* WPS Leasing, our consolidated subsidiary, has a note payable to our parent company, Integrys Energy Group. At December 31, 2014, the current portion of the note payable was $2.5 million.

The following table shows activity associated with related party transactions:

(Millions)	2014	2013	2012
Electric transactions			
Sales to UPPCO (1)	**$ 15.3**	$ 22.8	$ 22.2
Sales to Integrys Transportation Fuels, LLC	**0.1**	—	—
Natural gas transactions (2)			
Sales to IES	**0.6**	0.5	0.6
Purchases from IES	**2.5**	0.9	0.7
Interest expense (3)			
Integrys Energy Group	**0.5**	0.5	0.5
Transactions with equity-method investees			
Charges from ATC for network transmission services	**99.0**	98.4	94.2
Charges to ATC for services and construction	**8.6**	9.5	10.4
Net proceeds from WRPC sales of energy to MISO	**—**	—	2.9
Purchases of energy from WRPC	**3.7**	3.7	5.0
Charges to WRPC for operations	**1.4**	0.9	0.8
Equity earnings from WPS Investments, LLC (4)	**9.5**	10.2	10.2

(1) Includes sales through the date of the sale of UPPCO in August 2014, by Integrys Energy Group.

(2) Includes sales and purchases through the date of the sale of IES in November 2014, by Integrys Energy Group.

(3) WPS Leasing, our consolidated subsidiary, has a note payable to our parent company, Integrys Energy Group.

(4) WPS Investments, LLC is a consolidated subsidiary of Integrys Energy Group that is jointly owned by Integrys Energy Group and us. At December 31, 2014, we had an 10.98% interest in WPS Investments accounted for under the equity method. Our ownership percentage has continued to decrease as additional equity contributions are made by Integrys Energy Group to WPS Investments.

Note 26—Quarterly Financial Information (Unaudited)

(Millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2014					
Operating revenues	**$ 555.7**	**$ 358.8**	**$ 370.4**	**$ 397.4**	**$ 1,682.3**
Operating income	**87.6**	**36.5**	**77.9**	**56.4**	**258.4**
Net income attributed to common shareholder	**50.3**	**17.1**	**42.2**	**28.0**	**$ 137.6**
2013					
Operating revenues	$ 433.4	$ 367.8	$ 371.9	$ 406.2	$ 1,579.3
Operating income	77.4	46.9	65.2	50.5	240.0
Net income attributed to common shareholder	44.6	25.9	37.0	27.3	134.8

Because of various factors, the quarterly results of operations are not necessarily comparable.

H. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors and Stockholders of Wisconsin Public Service Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Public Service Corporation and subsidiary (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, common shareholder’s equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Wisconsin Public Service Corporation and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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.

/s/ DELOITTE & TOUCHE LLP

March 2, 2015

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

IITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined by Securities Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based upon that evaluation, management, including our Chief Executive Officer and Chief Financial Officer, has concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management Report on Internal Control over Financial Reporting

For our Management Report on Internal Control Over Financial Reporting see Section A of Item 8.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Name and Age [(1)]		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	61	Chairman and Chief Executive Officer of Integrys Energy Group and Director of WPS	01-01-14
		Chairman, President and Chief Executive Officer of Integrys Energy Group and Director of WPS	05-10-11
		Chairman, President and Chief Executive Officer of Integrys Energy Group and Chairman and Director of WPS	04-01-10
		President and Chief Executive Officer of Integrys Energy Group and Chairman and Director of WPS	03-16-09
Lawrence T. Borgard	53	President and Chief Operating Officer – Integrys Energy Group and Chairman and Chief Executive Officer and Director of WPS	01-01-14
		President and Chief Operating Officer – Utilities of Integrys Energy Group and Chairman and Chief Executive Officer and Director of WPS	12-25-11
		President and Chief Operating Officer – Utilities of Integrys Energy Group and Chairman, President and Chief Executive Officer and Director of WPS	05-10-11
		President and Chief Operating Officer – Utilities of Integrys Energy Group and President and Chief Executive Officer and Director of WPS	04-05-09
Charles A. Cloninger	56	Executive Vice President, Electric Segment of Integrys Energy Group and President and Director of WPS	05-15-14
		President and Director of WPS	01-24-12
		President of WPS	12-25-11
		President – Minnesota Energy Resources and Michigan Gas Utilities	10-05-08
Phillip M. Mikulsky	66	Executive Vice President – Corporate Initiatives and Chief Security Officer of Integrys Energy Group and Director of WPS	01-01-13
		Executive Vice President – Business Performance and Shared Services of Integrys Energy Group and Director of WPS	12-26-10
		Executive Vice President – Corporate Development and Shared Services of Integrys Energy Group and Director of WPS	09-21-08
William E. Morrow	58	Executive Vice President, Gas Segment of Integrys Energy Group and Director of WPS	05-16-14
		Vice President – Gas Engineering – Integrys Business Support	07-07-08
Mark A. Radtke	53	Executive Vice President – Shared Services and Chief Strategy Officer of Integrys Energy Group and Director of WPS	01-01-13
		Executive Vice President and Chief Strategy Officer of Integrys Energy Group and Director of WPS	05-10-11
		Executive Vice President and Chief Strategy Officer of Integrys Energy Group	12-26-10
		Chief Executive Officer – Integrys Energy Services	01-10-10
		President and Chief Executive Officer – Integrys Energy Services	06-01-08
James F. Schott	57	Executive Vice President and Chief Financial Officer of Integrys Energy Group and WPS and Director of WPS	05-16-14
		Vice President and Chief Financial Officer of Integrys Energy Group and WPS and Director of WPS	01-01-13
		Vice President – External Affairs of Integrys Energy Group and WPS and Director of WPS	05-12-10
		Vice President – External Affairs of Integrys Energy Group and Vice President – Regulatory Affairs and Director of WPS	04-01-10
		Vice President – External Affairs of Integrys Energy Group and Vice President – Regulatory Affairs	03-22-10
		Vice President – Regulatory Affairs	07-18-04
Linda M. Kallas	55	Vice President and Controller of Integrys Energy Group and WPS	05-15-13
		Vice President and Corporate Controller of Integrys Energy Group and WPS	09-01-12
		Vice President of Finance and Accounting Services of Integrys Energy Group	06-06-07
William J. Guc	45	Vice President and Treasurer of Integrys Energy Group and Treasurer of WPS	12-01-10
		Vice President – Finance and Accounting and Controller – Integrys Energy Services	03-07-10
		Vice President and Controller – Integrys Energy Services	09-21-08
William D. Laakso	52	Vice President and Chief Human Resources Officer of Integrys Energy Group and Director of WPS	05-15-14
		Vice President – Human Resources and Corporate Communications of Integrys Energy Group and Director of WPS	01-01-13
		Vice President – Human Resources of Integrys Energy Group and Director of WPS	09-21-08
Jodi J. Caro	49	Vice President, General Counsel and Secretary of Integrys Energy Group and Secretary of WPS	11-09-12
		Vice President, General Counsel and Assistant Secretary	02-19-12
		Vice President of Legal Services	01-07-08

(1) Officers and their ages are as of December 31, 2014. None of the executives and/or directors listed above are related by blood, marriage, or adoption to any of the other officers listed or to any of our directors. Each officer holds office until his or her successor has been duly elected and qualified, or until his or her death, resignation, disqualification, or removal.

Our Board of Directors is comprised solely of inside directors, and we do not have any standing committees of our Board of Directors. The role of an effective director inherently requires certain personal qualities, such as integrity, as well as the ability to comprehend, discuss, and critically analyze materials and issues that are presented so that the director may exercise judgment and reach conclusions in fulfilling his or her duties and fiduciary obligations. We believe that the specific background of each director, as set forth in the table above, evidences their ability to serve as a director and, accordingly, led to the conclusion that each of the directors should continue to serve as a director.

We are a wholly owned subsidiary of Integrys Energy Group. See Item 10 of Integrys Energy Group's Annual Report on Form 10-K for the year ended December 31, 2014, for information related to Section 16 compliance.

Integrys Energy Group has adopted a Code of Conduct, which covers us and serves as our Code of Business Conduct and Ethics. The Code of Conduct applies to all of our directors, officers, and employees, including the Chief Executive Officer, Chief Financial Officer, Controller, and any other persons performing similar functions.

Integrys Energy Group's Code of Conduct may be accessed on the Integrys Energy Group website at www.integrysgroup.com by selecting "Investors," then selecting "Corporate Governance," and then selecting "Governance Documents." It is available in print, without charge, to any shareholder who requests it from the Company's Secretary. Amendments to, or waivers from, the Code of Conduct will be disclosed on Integrys Energy Group's website within the prescribed time period.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The purpose of this Compensation Discussion and Analysis is to provide material information that is necessary for an understanding of our compensation policies and decisions relating to our named executive officers, including the identification of key components of our executive compensation program, and an explanation of the purpose of each key component. Our named executive officers for 2014 consisted of the following:

- Lawrence T. Borgard, Chief Executive Officer;
- James F. Schott, Executive Vice President and Chief Financial Officer;
- Charles A. Schrock, Chairman and Chief Executive Officer of Integrys Energy Group;
- Charles A. Cloninger, President; and
- Mark A. Radtke, Executive Vice President - Shared Services and Chief Strategy Officer of Integrys Energy Group

This discussion relates specifically to Mr. Cloninger, as Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke are also named executive officers of Integrys Energy Group, and the compensation paid to them is reported in the 2014 Integrys Energy Group Form 10-K, Item 11 and not herein. The compensation reported below reflects total compensation paid to Mr. Cloninger in consideration of his service to Integrys Energy Group and its subsidiaries, including us. For the “Compensation Discussion and Analysis” related to Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11, which addresses, among other things, the short-term incentive compensation, the long-term incentive compensation and the other benefits paid or payable to these named executive officers.

On June 22, 2014, Integrys Energy Group entered into an Agreement and Plan of Merger with Wisconsin Energy Corporation. We discuss below the impact of this proposed transaction on our executive compensation program.

Compensation Philosophy and Objectives

We are a wholly owned subsidiary of Integrys Energy Group. As such, we do not have a standing compensation committee because our executives participate in the compensation programs and plans of Integrys Energy Group, which are administered by the Compensation Committee of Integrys Energy Group's Board of Directors (referred to as the Committee). The Committee presents recommendations regarding appropriate compensation packages for our named executive officers to the Integrys Energy Group Board of Directors for its approval. The recommendations of the Committee are based on the same compensation philosophy and use of market studies as those used in determining compensation for executives of Integrys Energy Group. For information relating to these matters, as well as a discussion of the role of the Committee and the role of advisors to the Committee, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Actions Taken in 2014 in Light of Proposed Merger of Integrys Energy Group

In light of the proposed merger, Integrys Energy Group took certain actions to accelerate the vesting and/or payment of certain equity or incentive compensation benefits, to provide the Integrys Energy Group and its designated employees, including our named executive officers, with greater flexibility to manage the costs and cash flow associated with such equity and incentive compensation benefits.

Specifically, in October 2014, all outstanding unvested stock options held by designated employees, including our named executive officers, became fully vested and exercisable. This action did not involve the granting of additional options or any change in the consideration required to be paid by the employee in order to exercise an option. The change provided each designated employee with additional flexibility, if desired for tax planning or other reasons, to exercise the options prior to the consummation of the merger. Any exercise of the options must be in accordance with the terms of the 2010 Omnibus Incentive Compensation Plan. Outstanding options held at consummation of the merger will be canceled in exchange for a cash payment. Further, in December 2014, Integrys Energy Group paid to designated employees, including our named executive officers, 90% of the estimated 2014 short-term executive incentive award and 90% of the estimated 2012-2014 long-term performance award, based upon total shareholder return results calculated as of December 15, 2014. These payments were subject to all terms and conditions of the 2010 Omnibus Incentive Compensation Plan. In February 2015, the final 2014 short-term executive incentive and 2012-2014 long-term performance award levels were calculated and certified by the Committee. Because the final 2014 short-term executive incentive award was greater than the amount paid in December 2014, the employees will receive an additional payment in 2015 equal to the difference between the final short-term executive incentive award and the amount of the December 2014 payment. Similarly, because the final 2012-2014 long-term performance award was greater than the amount paid in December 2014, the employees will receive an additional payment in 2015 equal to the difference between the final long-term incentive award and the amount of the December 2014 payment. Had either the final 2014 short-term executive incentive or 2012-2014 long-term performance awards been less than the amounts paid to the respective employees in December 2014, the employees would have been required to repay the amount by which the December 2014 payment exceeded the final award level.

Base Salary

Base salary is used to provide cash income to executives to compensate them for services rendered during the fiscal year. Salary increases for 2014 were determined by the Committee based on recommendations of the Chief Executive Officer of Integrys Energy Group, which may include overall company performance and individual performance of the executive and the Committee's evaluation of current market data as provided by the independent executive compensation consultant hired by the Committee. In December 2013, the Committee granted a base salary increase for 2014 of 2.6% for all of the named executive officers, except for Mr. Borgard and Mr. Schott, who each received a 10% increase in order to bring their base pay closer to the market median. Base salaries for 2014 for our named executive officers were competitive with the market median at the time that the base salaries were approved. Setting base salary at or near market median levels allows the company to be competitive in the marketplace.

Short-Term Incentive Compensation

All of our named executive officers participated in the Integrys 2014 Executive Incentive Plan (Incentive Plan). Provided below are the specific performance goals and measurement weightings established for Mr. Cloninger.

	Charles A. Cloninger
Diluted EPS – Adjusted (1)	70%
Environmental Impact (2)	10%
Customer Satisfaction – Utility Customers (3)	10%
Safety (4)	10%

(1) Performance is measured based on Integrys Energy Group diluted earnings per share, which is based on forecasted net income available for common shareholders used to establish investor guidance, and adjusted on an after-tax basis.

(2) Performance is measured based on the implementation of projects and activities in 2014 that reduced annual emissions of carbon dioxide (CO_2) and other greenhouse gases.

(3) Performance is measured based on customer satisfaction through surveys performed by an outside vendor related to customer effort, service quality, and customer value.

(4) Performance is measured based on days-away, restricted duty, or job transfer (DART) incident rates and safety business plans and those at UPPCO, until it was sold by Integrys Energy Group in August 2014.

Under the Incentive Plan, no payouts for financial measure results are made to any of our named executive officers if the Diluted EPS – Adjusted threshold level is not attained. In addition, Incentive Plan payouts related to nonfinancial measures are reduced by 50% if the Diluted EPS – Adjusted threshold level is not attained.

Threshold, target and superior performance levels for each goal, as well as the weighting of each measure, are approved by the Committee. For each of the short-term incentive measures, the Committee sets specific performance levels early in the plan year and factors in stretch performance objectives in developing the performance measures. Threshold levels represent minimally acceptable performance, target levels represent performance that should typically be achievable in any given year, and superior levels represent stellar performance beyond that typically achievable in any given year.

Provided below are the specific payout levels established for 2014 for Mr. Cloninger.

	Payout Levels (as a Percent of Actual Paid Base Salary)		
Named Executive Officer	Threshold	Target	Superior
Charles A. Cloninger	—	45%	90%

Provided below are threshold, target and superior levels, as well as information related to actual results achieved for 2014 and related payout percentage for the financial measure:

				2014 Actual Results	
Financial Measure	Threshold	Target	Superior	Amount	Payout Percent of Target
Diluted EPS – Adjusted	$ 3.38	$ 3.60	$ 3.82	$ 3.31	0%

In making the determination as to the payout related to the financial measure, as provided for in the Incentive Plan approved by the Committee at the beginning of the year, the Committee concluded that certain adjustments to the Diluted EPS – Adjusted measure were appropriate because the events were nonrecurring in nature and the accounting effects of these items were not indicative of the performance of our named executive officers during 2014. The types of these adjustments were specifically allowed for in the Incentive Plan and included adjustments related to the sale of UPPCO and IES. The total adjustment to the Diluted EPS – Adjusted result was $0.30, all adjustments approved by the Committee were consistent with the types of adjustments allowed under the Incentive Plan.

The 2014 nonfinancial measures and performance range results, in general, are provided in the following table:

Nonfinancial Measures	Range of Performance Result
Environmental Impact	Below Threshold
Customer Satisfaction – Utility Customers	Between Target and Superior
Safety	Between Threshold and Target

The amount of total payouts awarded under the Incentive Plan for Mr. Cloninger, along with the payout percentages as a percent of targets and individual base salary earnings, are summarized in the table below.

	Charles A. Cloninger
Amount of Payout	$ 14,290
Payout as Percent of Target	11.01%
Payout as Percent of Base Salary	4.96%

The Committee believes it is important to establish performance targets and incentives that align executive compensation with financial and operational performance, promote value-driven decision making by executives and provide total compensation levels that are competitive in the market. Payout is made on any individual measure with results above threshold (provided that no payout for any financial measure is made unless the Diluted EPS – Adjusted threshold is reached, and payouts related to nonfinancial measures are also reduced by 50% if the Diluted EPS – Adjusted threshold is not reached). Company performance and the use of stretch performance objectives have had an effect on payout levels, with payouts for our named executive officers ranging from 9.86% to 122.61% of target and from 4.96% to 120.09% of actual paid base salary during the 2012 through 2014 plan performance periods.

Long-Term Incentive Compensation

The long-term incentive compensation granted by the Committee for 2014 as a percent of annualized base salary for Mr. Cloninger was 75%.

Other Benefits and Plans

We have certain other plans which provide, or may provide, cash compensation and benefits to our named executive officers. These benefits and plans include a nonqualified deferred compensation plan, a qualified pension plan, a nonqualified pension restoration plan and supplemental retirement plan, and perquisites. We also provide life insurance as part of our compensation package. The Committee considers all of these benefits and plans when reviewing total compensation of our named executive officers.

Deferred Compensation Plan

Our named executive officers may participate in the nonqualified Integrys Energy Group Deferred Compensation Plan. This nonqualified benefit allows eligible executives to defer 1% to 80% of base salary, annual short-term incentive, and long-term incentive compensation (other than options for Integrys Energy Group common stock) on a pre-tax (federal and state) basis.

Qualified Pension Plan

Our named executive officers are eligible to participate in the qualified Integrys Energy Group Retirement Plan (referred to as the pension plan) upon completion of one year of service and 1,000 or more hours of work during that year. The pension plan requires three years of employment or the attainment of age 65 to be vested in the plan.

For a more detailed discussion of the pension plan, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Provided below is the pension service credit for Mr. Cloninger.

Named Executive Officer	Accumulated Total Service Credits Earned as of December 31, 2014
Charles A. Cloninger	467%

The pension plan does not allow for granting of additional service credit not otherwise authorized under the plan terms. Provided in the Pension Benefits Table for 2014 below is a tabulation of the present value of the accumulated pension benefit using full years of credited service only.

Pension Restoration Plan and Supplemental Retirement Plan

Our named executive officers receive a nonqualified pension restoration benefit under the Nonqualified Pension Restoration Plan. Pension restoration provides a benefit based upon the difference between (1) the benefit the executive would have been entitled to under the pension plan if the maximum benefit limitation under IRS Section 415 and the compensation limitation under IRS Section 401(a)(17) did not apply, and if all base compensation and annual incentive amounts had been paid to the executive in cash rather than being deferred into the Integrys Energy Group Deferred Compensation Plan, and (2) the executive's actual benefit under the pension plan. The Nonqualified Deferred Compensation Table for 2014 below provides information on the deferrals into the Pension Restoration Plan and earnings for Mr. Cloninger.

In addition, the Integrys Energy Group Board of Directors, based on the recommendation of the Committee, has authorized certain executive officers to be provided with a nonqualified supplemental retirement benefit under the Supplemental Retirement Plan (SERP). This benefit provides income replacement when taking into account other retirement benefits provided to the eligible executive and assures that the eligible executive will receive 60% of his/her final average pay (over the last 36 months or the 3 preceding years, whichever is higher). To qualify for the full supplemental retirement benefit, the executive must have completed 15 years of service and retire/terminate after age 62. Reduced benefits are payable if the executive has attained age 55 and completed 10 years of service at retirement or termination.

Beginning in 2008, we made the decision to move away from the use of defined benefit plans for all nonunion employees, including executives, because of market trends. A ten-year transition period applies, which means that for new nonunion employees hired after 2008, no qualified or nonqualified defined benefit pension plans will exist for future benefit accruals. These plans are being replaced with defined contribution plans.

Nonqualified defined contributions will be allocated in the deferred compensation plan. These include contributions in conjunction with earnings over the compensation limit that are not considered for the qualified age and service contribution. Our named executive officers are eligible for a nonqualified defined contribution supplemental retirement contribution. In addition, our named executive officers are eligible for a nonqualified defined contribution credit in the amount of 5% of eligible earnings. These nonqualified contributions are considered as an offset to the defined benefit supplemental retirement plan for years 2013 through 2017 for all named executive officers other than Mr. Cloninger and Mr. Schott (who are not eligible for the defined benefit supplemental retirement plan).

Life Insurance

Our named executive officers are eligible for an enhanced life insurance benefit of up to three times their annual base salary, with a maximum benefit level (taking into account both employer-provided coverage and any supplemental coverage that the officer voluntarily purchases) of $1,500,000. Accidental death and dismemberment coverage is also provided for these same named executive officers up to three times their annual base salary, subject to a separate $1,500,000 maximum benefit level. The IRS requires that imputed income be calculated and recorded for company-paid life insurance in excess of $50,000. In compliance with IRS regulations, imputed income is recorded to the extent that an executive's life insurance benefit exceeds this limit. Listed below is the life insurance coverage in place for Mr. Cloninger as of December 31, 2014.

Named Executive Officer	Life Insurance Coverage ($)
Charles A. Cloninger	869,000

Perquisites

Our named executive officers are provided with a modest level of personal benefits. These may include payments for executive physicals, financial counseling, home office equipment and office parking.

Change in Control Program

The Committee has authorized each of our named executive officers to receive protection and associated benefits in the event of a covered termination following a change in control of Integrys Energy Group. These arrangements between our named executive officers and Integrys Energy Group each contain a "double trigger" arrangement, whereby a payment is made only if there is a change in control of Integrys Energy Group and the executive is actually terminated or terminates employment under certain circumstances after being demoted or after certain other adverse changes in the executive's working conditions or status. The Committee periodically reviews the payment and benefit levels in the change in control arrangements and the triggers to ensure that they remain competitive and appropriate. As part of this process, no tax gross-up provisions are being provided to our named executive officers. The Committee conducted a review of the program again in 2014 and concluded that the program continues to meet our objectives and remains consistent with current market practices.

For a more detailed discussion of the change in control benefits, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Common Stock Ownership Guidelines

We believe that it is important to align executive and shareholder interests by defining stock ownership guidelines for executives. Because we are wholly owned by Integrys Energy Group, the stock ownership guidelines are based on Integrys Energy Group common stock. For 2014, our named executive officers are expected to retain at least 50% of their future vested stock awards until certain levels of common stock are owned, with such levels generally ranging from one to five times base annual salary.

In 2014, the target level for ownership of Integrys Energy Group common stock was based on a target level of stock ownership equal to two times the target value of the executives' most recent regular long-term incentive grant, which translates to the following multiple of salary:

Named Executive Officer	Salary Multiple
Charles A. Cloninger	1.50

As of December 31, 2014, all of our named executive officers are complying with our stock ownership guidelines.

Summary Compensation Table for 2014

The following table sets forth information concerning compensation earned or paid to Mr. Cloninger for the past three fiscal years during which he was a named executive officer: (1) the dollar value of base salary and bonus earned during the applicable fiscal years; (2) the aggregate grant date fair value of stock and option awards, as computed in accordance with the Compensation – Stock Compensation Topic of the FASB ASC (all stock option awards in this and the other tables relate to Integrys Energy Group common stock); (3) the dollar value of earnings for services pursuant to awards granted during the applicable fiscal years under nonequity incentive plans; (4) the change in pension value and nonqualified compensation earnings during the applicable fiscal years; (5) all other compensation for the applicable fiscal years; and (6) the dollar value of total compensation for the applicable fiscal years. This Summary Compensation Table for 2014 and the tables that follow reflect the compensation paid to Mr. Cloninger for all services rendered in all capacities to Integrys Energy Group and its subsidiaries, including us, regardless of whether the compensation was paid by Integrys Energy Group or any of its subsidiaries. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($)	Stock Awards ($) (2)	Option Awards ($) (2)	Nonequity Incentive Plan Compensation ($) (3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (4)	All Other Compensation ($) (5)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Charles A. Cloninger, President	2014	288,357	—	164,449	45,600	14,290	182,558	119,025	814,279
	2013	281,050	—	127,173	47,613	155,070	112,508	43,646	767,060
	2012	275,000	—	144,277	40,969	45,803	217,685	15,396	739,130

(1) Amounts shown include amounts deferred into the Integrys Energy Group Deferred Compensation Plan. See the Nonqualified Deferred Compensation Table for 2014 for more information.

(2) The amounts shown in columns (e) and (f) reflect the grant date fair value of the awards computed in accordance with the Compensation – Stock Compensation Topic of the FASB ASC. See Note 20, Stock-Based Compensation, for more information regarding the assumptions made in valuing the stock and option awards.

(3) Nonequity incentive compensation is normally payable annually in the first quarter of the next fiscal year, and a portion may be deferred at the election of Mr. Cloninger. Payment is calculated based on the measurement outcomes and as a percent of adjusted gross base salary earnings from the Company for services performed during the payroll year. As discussed above in the Compensation Discussion and Analysis, in December 2014, we paid Mr. Cloninger 90% of the estimated 2014 short-term executive incentive award. In February 2015, the final 2014 short-term executive incentive was calculated and certified by the Committee. Because the final 2014 short-term executive incentive award was greater than the amount paid in December 2014, Mr. Cloninger will receive an additional payment in 2015 equal to the difference between the final short-term incentive award and the amount of the December 2014 payment.

(4) The amounts shown in relation to the change in pension value increased due to the decline in the overall interest rates. The calculation of above-market earnings on nonqualified deferred compensation is based on the difference between 120% of the applicable federal long-term rate (AFR) and the rate of return received on Reserve Accounts A and B. Provided below are the actual rates of return used in the calculation. Note that Reserve Account A was frozen to new deferrals beginning on January 1, 1996. Reserve Account B was frozen to new deferrals beginning on April 1, 2008.

Time Period	AFR 120%	Reserve A – Daily	Reserve B – Daily
January 2014 – March 2014	4.20%	9.5046%	6.7478%
April 2014 – September 2014	3.99%	10.4282%	7.4127%
October 2014 – December 2014	3.47%	11.0933%	7.8928%

(5) The amounts shown include other compensation items consisting of life insurance premiums, imputed income from life insurance benefits, and Employee Stock Ownership Plan (ESOP) matching contributions, age and service 401(k) contributions, and employer nonqualified deferred compensation contributions. For individual items included in column (i) that were in excess of $10,000, see the table below reflecting these contributions.

Named Executive Officer	ESOP ($)	401(k) Age/Service ($)	Deferred Compensation ($)
Charles A. Cloninger	17,610	18,200	78,278

As discussed above in the Compensation Discussion and Analysis, in October 2014, all outstanding but unvested stock options held by Mr. Cloninger became fully vested and exercisable. This action did not involve the granting of additional options or any change in the consideration required to be paid by Mr. Cloninger in order to exercise an option. See the discussion above in the Compensation Discussion and Analysis under the heading "Actions Taken in 2014 in Light of Proposed Merger of Integrys Energy Group."

Other than as noted above, with regard to equity awards, no re-pricing, extension of exercise periods, change of vesting or forfeiture conditions, change or elimination of performance criteria, change of bases upon which returns are determined, or any other material modification of any outstanding option or other equity-based award occurred during fiscal years reported in the table.

Grants of Plan-Based Awards Table for 2014

The following table sets forth information regarding all incentive plan awards that were made to Mr. Cloninger during 2014, including equity- and nonequity-based awards. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

		Estimated Future Payouts Under Nonequity Incentive Plan Awards Annual Incentive Plan (1)			Estimated Future Payouts Under Equity Incentive Plan Awards Performance Share Program			All Other Stock Awards: Number of Shares of Stock or Units (#) Restricted Stock Program	All Other Option Awards: Number of Securities Underlying Options (#) Stock Option Program	Exercise or Base Price Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) (2)
Name	Grant Date	Threshold ($)	Target ($)	Superior ($)	Threshold (#)	Target (#)	Superior (#)				
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Charles A. Cloninger	2014	—	130,269	260,537							
	02/13/14				1,361	2,721	5,442				120,486
	02/13/14							796			43,963
	02/13/14								6,806	55.23	45,600

(1) Based on the Integrys 2014 Executive Incentive Plan payout percentages. For more information, see the 2014 Integrys Energy Group Form 10-K, Item 11.

(2) Performance shares are valued at $44.28, the target payout value derived from a Monte Carlo simulation. Restricted stock units are valued at $55.23, the closing stock price on the grant date. Stock options are valued at $6.70 on an accounting expense basis based on a proprietary "advance lattice" option pricing model.

As reflected in the table above, the Committee awarded restricted stock units to Mr. Cloninger in 2014 for the amounts indicated. The restricted stock units had a grant date fair market value per share of $55.23, based on the closing stock price on the date of the grant. The restricted stock units vest ratably over four years following the date of grant. The dividend rate paid on restricted stock units is equal to the dividend rate of all other outstanding shares of common stock. However, the dividends are deemed to be reinvested in additional restricted stock units which vest according to the vesting schedule.

Stock options were granted in 2014 to Mr. Cloninger. These were nonqualified stock options with a grant price equal to the closing stock price on the date of the grant. The per share grant price for these options is $55.23. One quarter of the options vest each year on the grant anniversary date. The options had a grant date fair value per option of $6.70 as determined pursuant to the Compensation – Stock Compensation Topic of the FASB ASC. The options have an expiration date of February 13, 2024.

Performance shares were granted in 2014 to Mr. Cloninger. These grants have a performance period that began on January 1, 2014, and will end on December 31, 2016. The shares are not paid out until the end of this performance period based on the final total shareholder return in comparison to the selected peer group.

For a discussion of the treatment of unvested restricted stock units, stock options and performance shares upon termination, see the discussion below under the heading “Termination of Employment.”

Outstanding Equity Awards Table for 2014

The following table sets forth information for Mr. Cloninger regarding outstanding awards under the stock option plan, restricted stock plan, incentive plans, and similar plans, including market-based values of associated rights and/or shares as of December 31, 2014. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

	Options Awards					Stock Awards [1]			
Name	Number of securities underlying unexercised options (#) Exercisable	Number of securities underlying unexercised options (#) Unexercisable	Equity incentive plan awards: Number of securities underlying unexercised unearned options (#)	Option exercise price ($)	Option expiration date	Number of shares or units of stock that have not vested (#)	Market value of shares or units of stock that have not vested ($)	Equity incentive plan awards: Number of unearned shares, units or other rights that have not vested (#) [2] [3]	Equity incentive plan awards: Market or payout value of unearned shares, units or other rights that have not vested ($) [2] [3]
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Charles A. Cloninger						2,129	165,743	5,519	429,654

(1) Integrys Energy Group stock price on December 31, 2014, was $77.85.

(2) The following table reflects the amounts of unvested restricted stock units and corresponding grant dates. Restricted stock units vest over four years, with 25% of the original grant amount vesting each year on the anniversary of the respective grant date.

Named Executive Officer	02/10/11	02/09/12	02/14/13	02/13/14
Charles A. Cloninger	213	431	655	830

(3) Included in columns (i) and (j) above are the performance shares pertaining to grants made in 2013 and 2014 for the performance periods of 2013–2015 and 2014–2016 and associated payout values, assuming that both grants will pay out at target following completion of each applicable performance period. Based on total shareholder return (TSR) performance as of December 31, 2014, the grant made in 2013 would pay out at 150% (above target) and the grant made in 2014 would pay out at 200% (above target). The following two tables show projected payouts of the 2013 and 2014 performance share grants assuming TSR performance as of December 31, 2014, as well as projected payouts that would occur assuming superior performance (200%).

2013 Performance Share Grant:

Named Executive Officer	Shares at 150% Payout (#)	Market Value ($)	Shares at 200% Payout (#)	Market Value ($)
Charles A. Cloninger	4,197	326,736	5,596	435,649

2014 Performance Share Grant:

Named Executive Officer	Shares at 200% Payout (#)	Market Value ($)	Shares at 200% Payout (#)	Market Value ($)
Charles A. Cloninger	5,442	423,660	5,442	423,660

Option Exercises and Stock Vested Table for 2014

The following table sets forth amounts received by Mr. Cloninger upon exercise of options (or similar instruments) or the vesting of stock (or similar instruments) during 2014. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

	Option Awards		Stock Awards *	
Name	Number of shares acquired on exercise (#)	Value realized on exercise ($)	Number of shares acquired on vesting (#)	Value realized on vesting ($)
(a)	(b)	(c)	(d)	(e)
Charles A. Cloninger	28,625	522,300	3,815	271,809

* In December 2014, we paid to Mr. Cloninger 90% of the estimated 2012–2014 long-term performance award based upon total shareholder return results calculated on December 15, 2014. These performance shares had a performance period beginning on January 1, 2012, and ending on December 31, 2014. In February 2015, the final 2012–2014 long-term performance award level was calculated and certified by the Committee. Because the final 2012–2014 long-term incentive award was greater than the amount paid in December 2014, Mr. Cloninger will receive an additional payment in 2015 equal to the difference between the final long-term incentive award and the amount of the 2014 payment.

Pension Benefits Table for 2014

The following table sets forth the actuarial present value of Mr. Cloninger's accumulated benefit under each defined benefit plan, assuming benefits are paid at normal retirement age based on current levels of compensation. For Mr. Borgard, Mr. Schott, Mr. Schrock, and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11. All of our named executive officers are currently eligible for early retirement except Mr. Borgard and Mr. Radtke. No pension benefits were paid to any of the currently employed named executive officers during the year. Specific details of these benefits are discussed in more detail in the 2014 Integrys Energy Group Form 10-K, Item 11.

Name	Plan Name [(1)]	Number of years of credited service (#) [(2)]	Present value of accumulated benefits ($) [(3)]	Payments during last fiscal year ($)
(a)	(b)	(c)	(d)	(e)
Charles A. Cloninger	Retirement Plan	31	1,097,764	—
	Restoration Plan	31	482,277	—
	Total	31	1,580,041	—

(1) For a description of the material terms and conditions of the above-named plans, see the 2014 Integrys Energy Group Form 10-K, Item 11.

(2) Full years of credited service only. Actual plan benefits are calculated taking into account full and fractional years of credited service.

(3) Change in pension value during 2014 and present value of accumulated benefit at year-end:

Pension Plan

The amount shown is based on the present value of the projected pension plan account balances payable at the plan's normal retirement age (age 65). The projected age 65 pension plan account equals the participant's accrued account balance at year-end rolled forward with interest credits to age 65 using the plan's interest rate (2.50% at December 31, 2014, and 3.35% at December 31, 2013). The present value was determined using an interest rate consistent with assumptions used for financial reporting under the Compensation – Retirement Benefits Topic of the FASB ASC (4.10% at December 31, 2014, and 4.95% at December 31, 2013).

Since Mr. Cloninger is covered under the pension plan, the value of the temporary supplemental benefit has been added. The present value was determined assuming current commencement (if currently eligible) or commencement at earliest eligibility (generally age 55) and payment in a single lump sum form, using the plan's interest rate to calculate the lump sum payment (Pension Protection Act segment lump sum rates at December 31, 2014, and December 31, 2013) and using an interest rate consistent with assumptions used in financial reporting under the Compensation – Retirement Benefits Topic of the FASB ASC to determine the present value at year-end of the lump sum payable. The benefit was prorated based on current service over service from hire date to date of earliest eligibility.

Pension Restoration Plan

The amount shown is based on the present value of the projected pension plan account balance payable at the plan's normal retirement age (age 65). The projected age 65 pension plan account equals the participant's accrued account balance at year-end rolled forward with interest credits to age 65 using the plan's interest rate (2.50% at December 31, 2014, and 3.35% at December 31, 2013). The present value was determined using an interest rate consistent with assumptions used for financial reporting under the Compensation – Retirement Benefits Topic of the FASB ASC (3.35% at December 31, 2014, and 3.95% at December 31, 2013).

Nonqualified Deferred Compensation Table for 2014

The following table sets forth information regarding the contributions, earnings, and balances for Mr. Cloninger relative to the nonqualified deferred compensation plan for 2014. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Name	Executive Contributions in last fiscal year ($) [(1)]	Registrant contributions in last fiscal year ($) [(1)]	Aggregate earnings in last fiscal year ($) [(2)]	Aggregate withdrawals/ distributions ($)	Aggregate balance at last fiscal year-end ($) [(3)]
(a)	(b)	(c)	(d)	(e)	(f)
Charles A. Cloninger	64,744	69,577	135,727	—	820,187

(1) Deferrals into the Deferred Compensation Plan were made from compensation earned in 2014 and are reported in column (c) of the Summary Compensation Table for 2014, with the exception of short-term executive incentive and performance share amounts earned in 2013 but paid out and deferred in 2014. These amounts are as follows:

Name	Annual Incentive Payout	Performance Share Payout
Charles A. Cloninger	23,260	—

(2) Above-market earnings received on Reserve Accounts A and B are reported in column (h) of the Summary Compensation Table for 2014.

(3) The aggregate balance includes amounts shown in footnote (1) and the above-market earnings on Reserve Accounts A and B, which are included in column (h) of the Summary Compensation Table for 2014.

The following table sets forth the actual earnings during 2014 of each deferred compensation account held by Mr. Cloninger. For Mr. Borgard, Mr. Schott, Mr. Schrock and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Name	Aggregate earnings for Reserve A in last fiscal year ($)	Aggregate earnings for Reserve B in last fiscal year ($)	Aggregate earnings for Mutual Funds in last fiscal year ($)	Aggregate earnings for company stock in last fiscal year ($)	Aggregate earnings in last fiscal year ($)
Charles A. Cloninger	—	949	13,671	121,107	135,727

For further details regarding the deferred compensation accounts, including rates of return, see the 2014 Integrys Energy Group Form 10-K, Item 11. Upon retirement or termination of employment, distribution of our named executive officer's account will commence in January of the year that is both (1) following the calendar year of termination of employment and (2) at least six months following termination or later if a later date is selected by our named executive officer. Our named executive officers can elect a distribution period from 1 to 15 years. Payouts, withdrawals or other distributions cannot commence under the plan while our named executive officer is actively employed by us.

Termination of Employment

All of our named executive officers have been provided with arrangements such that, in the event of a termination following a change in control, a termination payment may be provided. For further details regarding the nature of these arrangements, see the 2014 Integrys Energy Group Form 10-K, Item 11. No change in control triggering event occurred in 2014 that affected our named executive officers.

Mr. Cloninger may voluntarily terminate his employment with the company, including pursuant to his retirement, or the company may terminate Mr. Cloninger's employment with or without cause (referred to as involuntary termination). If Mr. Cloninger's employment is terminated after a change in control event has occurred, in the circumstances discussed below, Mr. Cloninger is entitled to enhanced compensation benefits under the officer's change in control program. Prior to a change in control, if Mr. Cloninger terminates his employment, then he is entitled to receive only those benefits earned, accrued and vested prior to the date of termination. There are no provisions for enhanced payments or benefits to be granted to Mr. Cloninger for termination of employment, except as described below with regard to retirement.

If a change in control event has occurred and, during the term of the contract, Mr. Cloninger's employment is terminated by us for reasons other than "cause," or if Mr. Cloninger terminates for "good reason," then he receives the full change in control benefits. On the other hand, if a change in control event has occurred and Mr. Cloninger's employment is involuntarily terminated for "cause," or Mr. Cloninger voluntary terminates employment other than for "good reason," then he is entitled only to receive benefits that have already accrued and vested, but the executive officer is not entitled to receive the change in control benefits. For a description of the defined terms referenced above, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Mr. Cloninger is a participant in the change in control program that provides for a termination payment of up to two times his current salary and normal annual incentives. With regard to retirement, the only enhanced value Mr. Cloninger receives is derived from unvested equity grants, as vesting continues on stock options and restricted stock granted prior to retirement and performance periods continue on performance shares granted prior to retirement, provided that retirement occurs on or after December 31 of the calendar year in which the grant was made.

For additional detail regarding enhanced payments or benefits connected to termination of employment, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Provided below are estimated aggregate compensation and benefits that may be payable to Mr. Cloninger in the event of termination of employment. These estimates assume that termination occurred on the last business day of the last fiscal year (December 31, 2014).

Type of Termination	Charles A. Cloninger ($)
Retirement [1]	2,457,403
Change In Control [2]	3,153,952

(1) Mr. Cloninger is currently eligible for retirement as of December 31, 2014 under the pension program, as specified in the plan documents. Termination for reasons that are voluntary/involuntary/for cause, including death/disability, would be treated the same as retirement. Included in the value shown is the present value of future retirement benefit payments. Under the pension restoration plan and the SERP, certain participants will be paid a monthly benefit (for a fixed number of payments or a lifetime annuity). The present value of future monthly benefit payments was determined using an interest rate and mortality table consistent with assumptions used for financial reporting under the Compensation – Retirement Benefits Topic of the FASB ASC. Also included in the total is the enhanced value for any outstanding equity grants.

(2) The amounts reflected do not include potential forfeitures that an executive may experience in the event benefits are above the IRS change in control limit and the executive chooses to reduce the termination payment below such limit.

For estimated aggregate compensation and benefits that may be payable to Mr. Borgard, Mr. Schott, Mr. Schrock, and Mr. Radtke, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Director Compensation

At December 31, 2014, the eight directors consisted entirely of employees of Integrys Energy Group or its subsidiaries. The directors are Lawrence T. Borgard, Chairman; Charles A. Cloninger; William D. Laakso; Phillip M. Mikulsky; William E. Morrow; Mark A. Radtke; James F. Schott and Charles A. Schrock. None of these directors receive compensation for serving in the role of a director for us. Each director is compensated in his role as an employee of Integrys Energy Group or a subsidiary of Integrys Energy Group. For the compensation paid to Mr. Borgard, Mr. Mikulsky, Mr. Radtke, Mr. Schott, and Mr. Schrock, see the 2014 Integrys Energy Group Form 10-K, Item 11. For the compensation paid to Mr. Cloninger, see the sections immediately above. The remaining directors as of December 31, 2014, were paid the following total compensation (calculated in a similar fashion to how total compensation in column (j) of the Summary Compensation Table for 2014 is calculated) by Integrys Energy Group for the year ended December 31, 2014: William D. Laakso $709,516; and William E. Morrow $602,564.

Compensation Committee Report

For the Committee's report, see the 2014 Integrys Energy Group Form 10-K, Item 11.

Compensation Risk Assessment

For a discussion of the Committee's annual risk assessment of our compensation program, see the 2014 Integrys Energy Group Form 10-K, Item 11.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Equity Compensation Plan Information

Information required by this Item regarding equity compensation plans of Integrys Energy Group can be found in Item 12 of Integrys Energy Group's Annual Report on Form 10-K for the year ended December 31, 2014. Such information is incorporated by reference as if fully set forth herein.

Ownership of Voting Securities

All of our common stock is held by our parent, Integrys Energy Group.

The following table indicates the shares of Integrys Energy Group's common stock and stock options beneficially owned by our directors and executive officers as of February 1, 2015. None of the persons listed beneficially owns shares of any other class of our or Integrys Energy Group's equity securities.

	Amount and Nature of Shares Beneficially Owned		
Name and Title	**Aggregate Number of Shares Beneficially Owned** [1]	**Number of Shares Subject to Stock Options**	**Percent of Shares**
Charles A. Schrock, Director	171,469 [3]	—	[2]
Lawrence T. Borgard, Chairman, Chief Executive Officer, and Director	42,091	—	[2]
Charles A. Cloninger, President and Director	12,149	—	[2]
Phillip M. Mikulsky, Director	46,709	—	[2]
Mark A. Radtke, Director	57,877	—	[2]
James F. Schott, Executive Vice President and Chief Financial Officer and Director	11,831 [4]	—	[2]
William D. Laakso, Director	14,411	—	[2]
William E. Morrow, Director	9,848 [5]	—	[2]
All 11 directors and executive officers as a group	413,617	12,932	0.52%

(1) Aggregate number of shares beneficially owned includes:

- Shares and share equivalents of common stock held in the Integrys Energy Group Employee Stock Ownership Plan and the Integrys Energy Group, Inc. Deferred Compensation Trust;
- Stock options exercisable within 60 days of February 1, 2015;
- Restricted stock units vested within 60 days of February 1, 2015; and
- Performance shares paid out within 60 days of February 1, 2015 (based upon the actual payout as approved by the Integrys Energy Group Board of Directors on February 12, 2015).

Each director or officer has sole voting and investment power with respect to the shares reported, unless otherwise noted. No voting or investment power exists related to the stock options reported until exercised.

(2) Less than 1% of Integrys Energy Group's outstanding shares of common stock as of February 1, 2015.

(3) Includes 5,221 shares held in a joint revocable trust with spouse. Also includes 26,320 shares held by the Red Oak Foundation, Inc. Mr. Schrock can direct which charity the stock funds within the foundation go toward and can direct the foundation to sell or retain such shares.

(4) Includes 601 shares owned by spouse.

(5) Includes 3,000 shares jointly owned with spouse.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Our directors are also employed by us, our parent company, or a sister company.

Our directors and executive officers who are also executive officers of Integrys Energy Group are subject to Integrys Energy Group's policy regarding related person transactions. Information required by this Item regarding such related person transactions can be found in Item 13 of Integrys Energy Group's Annual Report on Form 10-K for the year ended December 31, 2014. Such information is incorporated by reference as if fully set forth herein.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following is a summary of the fees for professional services provided to us by Deloitte & Touche LLP in 2014 and 2013:

Fees	2014	2013
Audit Fees [1]	**$ 988,466**	$ 1,082,818
All Other Fees [2]	**990**	1,782
Total Fees	**$ 989,456**	$ 1,084,600

(1) *Audit Fees*. Consists of aggregate fees for the audits of the annual consolidated financial statements and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include services that are normally provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements, including comfort letters, consents, and other services related to SEC matters, and consultations arising during the course of the audits and reviews concerning financial accounting and reporting standards.

(2) *All Other Fees*. Consists of fees for services provided to us by Deloitte & Touche LLP for products and services other than the services reported above. All Other Fees relate to training provided in 2014 and 2013.

In considering the nature of the services provided by the independent registered public accounting firm, the Audit Committee of the Board of Directors of Integrys Energy Group (Audit Committee) determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with the independent registered public accounting firm and Integrys Energy Group's management and determined that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as those of the American Institute of Certified Public Accountants. The Audit Committee has approved in advance 100% of the audit services described above in accordance with its pre-approval policy.

For information on the Policy on Audit Committee Pre-Approval of Audit and Permissible Nonaudit Services of Independent Registered Public Accounting Firm, see the discussion in Item 14 of Integrys Energy Group's Annual Report on Form 10-K for the year ended December 31, 2014.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Documents filed as part of this report:

(1) Consolidated Financial Statements included in Part II at Item 8 above:

(2) Financial Statement Schedule.

The following financial statement schedule is included in Part IV of this report. Schedules not included herein have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(3) List of all exhibits, including those incorporated by reference.

See Exhibit Index.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 26, 2015.

WISCONSIN PUBLIC SERVICE CORPORATION

(Registrant)

By: /s/ Lawrence T. Borgard
Lawrence T. Borgard
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 26, 2015.

Signature	Title
Charles A. Cloninger*	Director
William D. Laakso *	Director
Phillip M. Mikulsky *	Director
William E. Morrow *	Director
Mark A. Radtke *	Director
Charles A. Schrock *	Director
/s/ Lawrence T. Borgard Lawrence T. Borgard	Chairman, Chief Executive Officer, and Director (principal executive officer)
/s/ James F. Schott James F. Schott	Executive Vice President, Chief Financial Officer and Director (principal financial officer)
/s/ Linda M. Kallas Linda M. Kallas	Vice President and Controller (principal accounting officer)
* By: /s/ Linda M. Kallas Linda M. Kallas	Attorney-in-Fact

SCHEDULE II
WISCONSIN PUBLIC SERVICE CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts
Years Ended December 31, 2014, 2013, and 2012
(In Millions)

Fiscal Year	Balance at Beginning of Year	Charged to Expense (1)	Deductions (2)	Balance at End of Year
2012	$ 3.0	$ 5.7	$ (6.2)	$ 2.5
2013	$ 2.5	$ 5.2	$ (5.2)	$ 2.5
2014	**$ 2.5**	**$ 7.3**	**$ (6.6)**	**$ 3.2**

(1) Net of recoveries.

(2) Represents amounts written off to the reserve, net of adjustments to regulatory assets.

EXHIBIT INDEX

Set forth below is a listing of all exhibits to this Annual Report on Form 10-K, including those incorporated by reference.

Certain other instruments, which would otherwise be required to be listed below, have not been so listed as such instruments do not authorize long-term securities in an amount that exceeds 10% of the total assets of us and our subsidiary on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request. Integrys Energy Group, Inc.'s SEC File No. is 1-11337.

Exhibit Number	Description of Documents
2.1*	Asset Contribution Agreement between ATC and Wisconsin Electric Power Company, Wisconsin Power and Light Company, WPS, Madison Gas & Electric Co., Edison Sault Electric Company, South Beloit Water, Gas and Electric Company, dated as of December 15, 2000. (Incorporated by reference to Exhibit 2A-3 to Integrys Energy Group's and WPS's Form 10-K for the year ended December 31, 2000.)
2.2* #	Purchase and Sale Agreement among WPS, Fox Energy OP, L.P., and Fox River Power LLC, dated as of September 28, 2012. (Incorporated by reference to Exhibit 2 to WPS's Form 10-Q/A for the quarter ended September 30, 2012, filed April 1, 2013.)
3.1	Restated Articles of Incorporation of WPS as effective May 26, 1972, and amended through May 31, 1988 and Articles of Amendment to Restated Articles of Incorporation of WPS dated June 9, 1993. (Incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-3, Reg. No. 333-182491, filed July 2, 2012.)
3.2	By-Laws of WPS, as amended through October 8, 2013. (Incorporated by reference to Exhibit 3.2 to WPS's Form 10-Q for the quarter ended September 30, 2013, filed November 7, 2013.)
4.1	First Mortgage and Deed of Trust, dated as of January 1, 1941, from WPS to U.S. Bank National Association (successor to First Wisconsin Trust Company), Trustee (Incorporated by reference to Exhibit 7.01 - File No. 2-7229); Supplemental Indenture, dated as of November 1, 1947 (Incorporated by reference to Exhibit 7.02 - File No. 2-7602); Supplemental Indenture, dated as of November 1, 1950 (Incorporated by reference to Exhibit 4.04 - File No. 2-10174); Supplemental Indenture, dated as of May 1, 1953 (Incorporated by reference to Exhibit 4.03 - File No. 2-10716); Supplemental Indenture, dated as of October 1, 1954 (Incorporated by reference to Exhibit 4.03 - File No. 2-13572); Supplemental Indenture, dated as of December 1, 1957 (Incorporated by reference to Exhibit 4.03 - File No. 2-14527); Supplemental Indenture, dated as of October 1, 1963 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of June 1, 1964 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of November 1, 1967 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of April 1, 1969 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Fifteenth Supplemental Indenture, dated as of May 1, 1971 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Sixteenth Supplemental Indenture, dated as of August 1, 1973 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Seventeenth Supplemental Indenture, dated as of September 1, 1973 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Eighteenth Supplemental Indenture, dated as of October 1, 1975 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Nineteenth Supplemental Indenture, dated as of February 1, 1977 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Twentieth Supplemental Indenture, dated as of July 15, 1980 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1980); Twenty-First Supplemental Indenture, dated as of December 1, 1980 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1980); Twenty-Second Supplemental Indenture dated as of April 1, 1981 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1981); Twenty-Third Supplemental Indenture, dated as of February 1, 1984 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1983); Twenty-Fourth Supplemental Indenture, dated as of March 15, 1984 (Incorporated by reference to Exhibit 1 to Form 10-Q for the quarter ended June 30, 1984); Twenty-Fifth Supplemental Indenture, dated as of October 1, 1985 (Incorporated by reference to Exhibit 1 to Form 10-Q for the quarter ended September 30, 1985); Twenty-Sixth Supplemental Indenture, dated as of December 1, 1987 (Incorporated by reference to Exhibit 4A-1 to Form 10-K for the year ended December 31, 1987); Twenty-Seventh Supplemental Indenture, dated as of September 1, 1991 (Incorporated by reference to Exhibit 4 to Form 8-K filed September 18, 1991); Twenty-Eighth Supplemental Indenture, dated as of July 1, 1992 (Incorporated by reference to Exhibit 4B - File No. 33-51428); Twenty-Ninth Supplemental Indenture, dated as of October 1, 1992 (Incorporated by reference to Exhibit 4 to Form 8-K filed October 22, 1992); Thirtieth Supplemental Indenture, dated as of February 1, 1993 (Incorporated by reference to Exhibit 4 to Form 8-K filed January 27, 1993); Thirty-First Supplemental Indenture, dated as of July 1, 1993 (Incorporated by reference to Exhibit 4 to Form 8-K filed July 7, 1993); Thirty-Second Supplemental Indenture, dated as of November 1, 1993 (Incorporated by reference to Exhibit 4 to Form 10-Q for the quarter ended September 30, 1993); Thirty-Third Supplemental Indenture, dated as of December 1, 1998 (Incorporated by reference to Exhibit 4D to Form 8-K filed December 18, 1998); Thirty-Fourth Supplemental Indenture, dated as of August 1, 2001 (Incorporated by reference to Exhibit 4D to Form 8-K filed August 24, 2001); Thirty-Fifth Supplemental Indenture, dated as of December 1, 2002 (Incorporated by reference to Exhibit 4D to Form 8-K filed December 16, 2002); Thirty-Sixth Supplemental Indenture, dated as of December 8, 2003 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed December 9, 2003); Thirty-Seventh Supplemental Indenture, dated as of December 1, 2006 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 30, 2006); Thirty-Eighth Supplemental Indenture, dated as of August 1, 2006 (Incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2006); Thirty-Ninth Supplemental Indenture, dated as of November 1, 2007 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 16, 2007); Fortieth Supplemental Indenture, dated as of December 1, 2008 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed December 4, 2008); Forty-First Supplemental Indenture, dated as of December 18, 2008 (Incorporated by reference to Exhibit 4.1 to Form 10-Q filed May 6, 2010); 42nd Supplemental Indenture, dated as of April 25, 2010 (Incorporated by reference to Exhibit 4.2 to Form 10-Q filed May 6, 2010); 43rd Supplemental Indenture, dated as of December 1, 2012 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 29, 2012); and 44th Supplemental Indenture, dated November 1, 2013 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 18, 2013.) All references to periodic reports are to those of WPS.

4.2	Indenture, dated as of December 1, 1998, between WPS and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4A to Form 8-K filed December 18, 1998); First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firstar Bank Milwaukee, N.A., National Association (Incorporated by reference to Exhibit 4C to Form 8-K filed December 18, 1998); Second Supplemental Indenture, dated as of August 1, 2001, between WPS and Firstar Bank, National Association (Incorporated by reference to Exhibit 4C of Form 8-K filed August 24, 2001); Third Supplemental Indenture, dated as of December 1, 2002, between WPS and U.S. Bank National Association (Incorporated by reference to Exhibit 4C of Form 8-K filed December 16, 2002); Fourth Supplemental Indenture, dated as of December 8, 2003, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed December 9, 2003); Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 30, 2006); Sixth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.2 to Form 10-K for the year ended December 31, 2006); Seventh Supplemental Indenture, dated as of November 1, 2007, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 16, 2007); Eighth Supplemental Indenture, dated as of December 1, 2008, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed December 4, 2008); Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 29, 2012); and Tenth Supplemental Indenture, dated November 1, 2013, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 18, 2013.) All references to periodic reports are to those of WPS.
10.1	Joint Power Supply Agreement among WPS, Wisconsin Power and Light Company, and Madison Gas and Electric Company, dated February 2, 1967. (Incorporated by reference to Exhibit 4.09 in File No. 2-27308.)
10.2*	Joint Power Supply Agreement among WPS, Wisconsin Power and Light Company, and Madison Gas and Electric Company dated July 26, 1973. (Incorporated by reference to Exhibit 5.04A in File No. 2-48781.)
10.3* #	Joint Plant Agreement by and between WPS and Dairyland Power Cooperative, dated as of November 23, 2004. (Incorporated by reference to Exhibit 10.19 to Integrys Energy Group's and WPS's Form 10-K for the year ended December 31, 2004.)
10.4	Basic Generating Agreement, Unit 4, Edgewater Generating Station, dated June 5, 1967, between Wisconsin Power and Light Company and WPS. (Incorporated by reference to Exhibit 4.10 in File No. 2-27308.)
10.5	Agreement for Construction and Operation of Edgewater 5 Generating Unit, dated February 24, 1983, between Wisconsin Power and Light Company, Wisconsin Electric Power Company, and WPS. (Incorporated by reference to Exhibit 10C-1 to WPS's Form 10-K for the year ended December 31, 1983.)
10.6	Amendment No. 1 to Agreement for Construction and Operation of Edgewater 5 Generating Unit, dated December 1, 1988. (Incorporated by reference to Exhibit 10C-2 to WPS's Form 10-K for the year ended December 31, 1988.)
10.7	Revised Agreement for Construction and Operation of Columbia Generating Plant among WPS, Wisconsin Power and Light Company, and Madison Gas and Electric Company, dated July 26, 1973. (Incorporated by reference to Exhibit 5.07 in File No. 2-48781.)
10.8+	Key Executive Employment and Severance Agreement entered into between Integrys Energy Group, Inc. and Phillip M. Mikulsky, as amended and restated effective June 21, 2014 (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group's Form 8-K filed June 25, 2014.)
10.9+	Form of Key Executive Employment and Severance Agreement entered into between Integrys Energy Group and each of the following: Charles A. Schrock, Lawrence T. Borgard and Mark A. Radtke. (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group's Form 8-K filed May 12, 2010.)
10.10+	Integrys Energy Group Executive Change in Control Severance Plan applicable to the following: William D. Laakso, James F. Schott, Jodi J. Caro, Linda M. Kallas, William J. Guc, William E. Morrow, and Charles A. Cloninger. (Incorporated by reference to Exhibit 10.3 to Integrys Energy Group's Form 10-K for the year ended December 31, 2010.)
10.11+	Form of Integrys Energy Group 2007 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved May 17, 2007. (Incorporated by reference to Exhibit 10.10 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.12+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved September 16, 2010. (Incorporated by reference to Exhibit 10.5 to Integrys Energy Group's Form 8-K filed September 22, 2010.)
10.13+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Performance Stock Right Agreement approved December 13, 2012 (Incorporated by reference to Exhibit 10.12 to Integrys Energy Group's Form 10-K for the year ended December 31, 2012.)
10.14+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement approved December 13, 2012 (Incorporated by reference to Exhibit 10.13 to Integrys Energy Group's Form 10-K for the year ended December 31, 2012.)
10.15+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved December 13, 2012 (Incorporated by reference to Exhibit 10.14 to Integrys Energy Group's Form 10-K for the year ended December 31, 2012).
10.16+	Form of Integrys Energy Group, Inc. 2014 Omnibus Incentive Compensation Plan Performance Stock Right Agreement approved May 15, 2014. (Incorporated by reference to Exhibit 4.2 to Integrys Energy Group's Form S-8 (Reg. No. 333-195989) filed May 15, 2014.)
10.17+	Form of Integrys Energy Group, Inc. 2014 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement approved May 15, 2014. (Incorporated by reference to Exhibit 4.3 to Integrys Energy Group's Form S-8 (Reg. No. 333-195989) filed May 15, 2014.)
10.18+	Form of Integrys Energy Group, Inc. 2014 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved May 15, 2014. (Incorporated by reference to Exhibit 4.4 to Integrys Energy Group's Form S-8 (Reg. No. 333-195989) filed May 15, 2014.)
10.19+	Integrys Energy Group, Inc. Deferred Compensation Plan, as Amended and Restated Effective January 1, 2014. (Incorporated by reference to Exhibit 10.15 to Integrys Energy Group's Form 10-K for the year ended December 31, 2013.)
10.20+	Integrys Energy Group, Inc. Pension Restoration and Supplemental Retirement Plan, as Amended and Restated Effective January 1, 2014. (Incorporated by reference to Exhibit 10.16 to Integrys Energy Group's Form 10-K for the year ended December 31, 2013.)

10.21+	Integrys Energy Group, Inc. 2005 Omnibus Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group's and WPS's Form 10-Q filed August 4, 2005.)
10.22+	Integrys Energy Group, Inc. 2007 Omnibus Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.17 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.23+	Integrys Energy Group 2010 Omnibus Incentive Compensation Plan, as amended. (Incorporated by reference to Exhibit 10.22 to Integrys Energy Group's Form 10-K for the year ended December 31, 2011.)
10.24+	Integrys Energy Group 2014 Omnibus Incentive Compensation Plan, as amended. (Incorporated by reference to Exhibit 4.1 to Integrys Energy Group's Form S-8 (Reg. No. 333-195989) filed May 15, 2014.)
10.25+	Integrys Energy Group, Inc. Transaction Retention Plan and form of Notice of Participation. (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group's Form 8-K filed June 25, 2014.)
21	Subsidiaries of WPS.
23	Consent of Independent Registered Public Accounting Firm for WPS.
24	Power of Attorney.
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for WPS.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for WPS.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for WPS.
101	Financial statements from the Annual Report on Form 10-K of WPS for the year ended December 31, 2014, filed on February 26, 2015, formatted in eXtensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income; (ii) the Consolidated Balance Sheets; (iii) the Consolidated Statements of Capitalization; (iv) the Consolidated Statements of Common Shareholder's Equity; (v) the Consolidated Statements of Cash Flows; (vi) the Notes to Consolidated Financial Statements; and (vii) document and entity information.

* Schedules and exhibits to this document are not filed therewith. The registrant agrees to furnish supplementally a copy of any such schedule or exhibit to the SEC upon request.

\+ A management contract or compensatory plan or arrangement.

\# Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of SEC pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934, as amended. The redacted material was filed separately with the SEC.

Exhibit 21

Affiliates and Subsidiaries of Wisconsin Public Service Corporation
December 31, 2014

- Wisconsin Public Service Corporation *
  - WPS Leasing, Inc. *
  - Wisconsin Valley Improvement Company (27.1% ownership) *
  - Wisconsin River Power Company (50% ownership) *
  - WPS Investments, LLC (approximately 10.98% ownership) *
    - American Transmission Company LLC (approximately 34.07% ownership) *
  - ATC Management Inc. (32.16% ownership of Class A Shares) *

All affiliated companies listed are 100% owned except as noted otherwise.

* Formed under Wisconsin law.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-199909 and 333-182491 on Form S-3, and 333-127889-01 and 333-71990-01 on Form S-8 of our report dated March 2, 2015, relating to the financial statements and financial statement schedule of Wisconsin Public Service Corporation and subsidiary appearing in this Annual Report on Form 10-K of Wisconsin Public Service Corporation and subsidiary for the year ended December 31, 2014.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
March 2, 2015

Exhibit 24

POWER OF ATTORNEY

WHEREAS, WISCONSIN PUBLIC SERVICE CORPORATION, a Wisconsin corporation, will file on or before the due date of March 2, 2015 with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, an annual report on Form 10-K, and

WHEREAS, each of the undersigned is a Director of Wisconsin Public Service Corporation;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints Lawrence T. Borgard, James F. Schott, Linda M. Kallas, and Jodi J. Caro or any one of them, as attorney, with full power to act for the undersigned and in the name, place and stead of the undersigned, to sign the name of the undersigned as Director to said annual report on Form 10-K and any and all amendments to said annual report, hereby ratifying and confirming all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has executed this document this 12th day of February, 2015.

/s/ Lawrence T. Borgard	/s/ Philip M. Mikulsky
Lawrence T. Borgard, Director and Chairman	Philip M. Mikulsky, Director
/s/ Charles A. Cloninger	/s/ Mark A. Radtke
Charles A. Cloninger, Director	Mark A. Radtke, Director
/s/ William D. Laakso	/s/ James F. Schott
William D. Laakso, Director	James F. Schott, Director
/s/ William E. Morrow	/s/ Charles A. Schrock
William E. Morrow, Director	Charles A. Schrock, Director

Exhibit 31.1

Certification of Chief Executive Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a)
or 15d-14(a) under the Securities Exchange Act of 1934

I, Lawrence T. Borgard, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Public Service Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2015

/s/ Lawrence T. Borgard
Lawrence T. Borgard
Chairman and Chief Executive Officer

Exhibit 31.2

Certification of Chief Financial Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a)
or 15d-14(a) under the Securities Exchange Act of 1934

I, James F. Schott, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Public Service Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2015

/s/ James F. Schott
James F. Schott
Executive Vice President and Chief Financial Officer

Exhibit 32

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Wisconsin Public Service Corporation (the "Company"), hereby certify, based on our knowledge, that the Annual Report on Form 10-K of the Company for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Lawrence T. Borgard
Lawrence T. Borgard
Chairman and Chief Executive Officer

/s/ James F. Schott
James F. Schott
Executive Vice President and Chief Financial Officer

Date: February 26, 2015

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by Wisconsin Public Service Corporation for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to Wisconsin Public Service Corporation and will be retained by Wisconsin Public Service Corporation and furnished to the Securities and Exchange Commission or its staff upon request.