INTEGRYS ENERGY GROUP, INC.
Form 10-K
March 02, 2015

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.
1-11337	INTEGRYS ENERGY GROUP, INC. (A Wisconsin Corporation) 200 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

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

Title of each class	Name of each exchange on which registered
Common Stock, $1 par value	New York Stock Exchange
6.00% Junior Subordinated Notes due 2073	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X]   No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]
Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ]   No [X]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.

$5,656,939,310 as of June 30, 2014

Number of shares outstanding of each class of common stock, as of February 25, 2015

Common Stock, $1 par value, 79,963,091 shares

INTEGRYS ENERGY GROUP, INC.
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
AMRP	Accelerated Natural Gas Main Replacement Program
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
ICC	Illinois Commerce Commission
IES	Integrys Energy Services, Inc.
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC (doing business as Trillium CNG)
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
N/A	Not Applicable
NSG	North Shore Gas Company
PDI	WPS Power Development LLC
PELLC	Peoples Energy, LLC (formerly known as Peoples Energy Corporation)
PGL	The Peoples Gas Light and Coke Company
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 the regulated businesses;
- 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 subsidiaries are subject;
- The possibility that the proposed merger with Wisconsin Energy Corporation does not close (including, but not limited to, due to the failure to satisfy the closing conditions), disruption from the proposed merger making it more difficult to maintain our business and operational relationships, and the risk that unexpected costs will be incurred during this process;
- 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 and our subsidiaries' 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 our subsidiaries operate;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries' counterparties, affiliates, and customers to meet their obligations;
- The ability to use tax credit, net operating loss, and/or charitable contribution carryforwards;

- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- Potential business strategies, including acquisitions or dispositions of assets or business, 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 financial performance of ATC and its corresponding contribution to our earnings;
- 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 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 Integrys Energy Group, Inc. The term "utility" refers to the regulated activities of the electric and natural gas utility companies, while the term "nonutility" refers to the activities of the electric and natural gas utility companies that are not regulated. The term "nonregulated" refers to activities at ITF, PDI, the Integrys Energy Group holding company, and the PELLC holding company. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, including financial and geographic information about each reportable business segment, see Note 28, Segments of Business, and Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Integrys Energy Group, Inc.

We are an energy holding company headquartered in Chicago, Illinois. We were incorporated in Wisconsin in 1993. Our wholly owned subsidiaries provide regulated natural gas and electricity, as well as nonregulated renewable energy and compressed natural gas products and services. In addition, we have a 34% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2014, we had four reportable segments with continuing operations and one reportable segment that only contained the discontinued operations related to IES's retail energy business. Our reportable segments are discussed below. In June 2014, we entered into an Agreement and Plan of Merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on this transaction.

Facilities

For information regarding our facilities, see Item 2, Properties. For our plant asset book values, see Note 7, 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, proxy statements, registration statements, and any amendments to these documents are available, free of charge, on our 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 our 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 our 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, proxy and registration statements, and other information (including exhibits) filed or furnished electronically with the SEC, at the SEC's website at www.sec.gov.

B. NATURAL GAS UTILITY OPERATIONS

Our natural gas utility segment includes the natural gas utility operations of MERC, MGU, NSG, PGL, and WPS. For MERC and MGU, both Delaware corporations, we acquired their existing natural gas distribution operations in Minnesota and Michigan in July 2006 and April 2006, respectively. NSG and PGL, both Illinois corporations, began operations in 1900 and 1855, respectively. We acquired NSG and PGL in February 2007 in the PELLC merger. WPS, a Wisconsin corporation, began operations in 1883.

Our natural gas utilities provide service to approximately 1.7 million residential, commercial and industrial, transportation, and other customers. Our customers are located in Chicago and the northern suburbs of Chicago, northeastern Wisconsin, various cities and communities throughout Minnesota, the southern portion of lower Michigan, and Michigan's Upper Peninsula.

Natural Gas Supply

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

Our natural gas supply requirements are met through a combination of fixed price purchases, index price purchases, contracted and owned storage, peak-shaving facilities, and natural gas supply call options. Our natural gas subsidiaries contract for fixed-term firm natural gas supply each year (in the United States and Canada) to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, our natural gas utilities 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 17, Commitments and Contingencies.

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

PGL owns and operates Manlove Field and a natural gas pipeline system that connects Manlove Field to Chicago and eight major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in PGL's regulatory rate base. PGL also uses a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to its wholesale customers. Customers deliver natural gas to PGL for storage through an injection into the storage reservoir, and PGL returns the natural gas to the customers under an agreed schedule through a withdrawal from the storage reservoir. Title to the natural gas does not transfer to PGL. PGL recognizes service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

The tables below are a rollforward of PGL's natural gas in storage balances related to the natural gas hub as well as natural gas hub service fees collected from wholesale customers:

Thousands of Dekatherms (MDth)	2014	2013	2012
Beginning Balance, January 1	5,143	5,240	5,261
Injections	3,104	7,000	7,000
Withdrawals	(6,028)	(7,097)	(7,021)
Ending Balance, December 31	2,219	5,143	5,240

(Millions)	2014	2013	2012
Natural gas hub service fees	$1.8	$4.3	$3.9

Our natural gas utilities 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 natural gas utilities' forecasted design peak-day throughput is 4,020 MDth for the 2014 through 2015 heating season.

The sources of our deliveries to customers (including transportation customers) for natural gas utility operations were as follows:

(MDth)	2014	2013	2012
Natural gas purchases	260,532	232,007	184,188
Natural gas purchases for electric generation	1,655	2,246	2,215
Customer-owned natural gas received	205,033	191,101	176,598
Underground storage, net	(12,692)	6,123	2,749

Hub fuel in kind *	80	179	179
Liquefied petroleum gas (propane)	71	1	1
Owned storage cushion injection	(1,138)	(1,097)	(1,097)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted-for natural gas	(7,876)	(12,992)	(8,037)
Total	445,665	417,568	356,796

* This delivered natural gas was originally provided by hub customers whose contract requires them to provide additional natural gas to compensate for lost and unaccounted-for natural gas in future deliveries.

Regulatory Matters

Our natural gas utility retail rates are regulated by the ICC, MPSC, MPUC, and PSCW. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Sales are made and services are rendered by the natural gas utilities pursuant to rate schedules on file with the respective commissions. These rate schedules contain various service classifications, which largely reflect customers' different uses and levels of consumption. Our natural gas utilities 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 hedging programs, the amount of which is also subject to applicable commission 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 respective 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 our natural gas utilities distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services, including PGL's natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the Pipeline and Hazardous Materials Safety Administration and the state commissions are responsible for monitoring and enforcing requirements governing our natural gas utilities' safety compliance programs for our pipelines under United States Department of Transportation regulations. These regulations include 49 Code of Federal Regulations (CFR) Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

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

See Note 25, Regulatory Environment, for information regarding rate cases, decoupling mechanisms, bad debt recovery mechanisms, and other cost recovery mechanisms at our natural gas utilities.

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 66% of its revenues in January, February, March, November, and December.

Competition

Although our natural gas retail rates are regulated by various commissions, the natural gas utilities 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, our natural gas utilities 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.

Our natural gas utilities all offer natural gas transportation service, and certain of our natural gas utilities also offer interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our natural gas utilities' distribution systems to transport the natural gas to their facilities. Our natural gas utilities 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 natural gas utilities' working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

C. ELECTRIC UTILITY OPERATIONS

For the periods presented in this Annual Report on Form 10-K, the electric utility segment included the electric utility operations of WPS and the electric utility operations of UPPCO until its sale in 2014. WPS, a Wisconsin corporation, began operations in 1883. In August 2014, we sold all of the stock of UPPCO. See Note 4, Dispositions, for more information.

The electric utility operations of WPS provide service to approximately 450,000 residential, commercial and industrial, wholesale, and other customers. WPS's 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

WPS is a member of MISO, a FERC-approved, independent, nonprofit organization, which operates a financial and physical electric wholesale market in the Midwest. WPS offers generation and bids customer load into the MISO market. MISO evaluates WPS's 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 WPS's 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, Acquisitions, for more information.

(2) See Note 17, 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, Acquisitions, for more information.

The PSCW requires WPS to maintain a planning reserve margin above its projected annual peak demand forecast to help ensure reliability of electric service to its 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.

WPS had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2014. In 2015, WPS expects 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 for WPS:

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 WPS's electric generation facilities. WPS's 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 WPS's lowest cost coal source of any of the subbituminous coal-producing regions in the United States. Historically, WPS has purchased coal directly from the producer for its wholly owned plants. WPS also purchases coal for the jointly owned Weston 4 plant, and Dairyland Power Cooperative reimburses WPS for their share of the coal costs. Wisconsin Power and Light Company purchases coal for the jointly owned Edgewater and Columbia plants, and WPS reimburses them for its share of the coal costs. At December 31, 2014, WPS had coal transportation contracts in place for 100% of its 2015 coal transportation requirements. See Note 17, Commitments and Contingencies, for more information on coal purchases and coal deliveries under contract.

Regulatory Matters

WPS's retail electric rates are regulated by the PSCW and the MPSC. The FERC regulates WPS's wholesale electric rates. WPS 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 WPS.

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(f), Revenues and Customer Receivables, for more information. WPS charges formula-based rates, as approved by the FERC, for the sale of electricity to its wholesale customers.

See Note 25, Regulatory Environment, for more information regarding WPS's rate cases and decoupling mechanisms.

Hydroelectric Licenses

WPS and WRPC (a company in which WPS has 50% ownership) have long-term licenses from the FERC for their 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 territories in the Upper Peninsula of Michigan, creating an active competitive market resulting in some lost load.

D. INTEGRYS ENERGY SERVICES

We sold the nonregulated retail energy business of IES on November 1, 2014. PDI, the energy asset business that was formerly a part of IES, remains but has been reclassified to the holding company and other segment, as PDI's operations are not material to the consolidated company.

E. ELECTRIC TRANSMISSION INVESTMENT

The electric transmission investment segment consists of our approximate 34% ownership interest in ATC. ATC, which began operations in 2001, owns and operates the electric transmission system, under the direction of the MISO, in parts of Wisconsin, Illinois, Minnesota and the Upper Peninsula of Michigan. ATC is subject to regulation by FERC as to rates, terms of service, and financing and by state regulatory commissions as to other aspects of business, including the construction of electric transmission assets. See Note 10, Equity Method Investments, for more information about ATC.

F. HOLDING COMPANY AND OTHER SEGMENT

The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, the operations of ITF, and the operations of PDI, the energy asset business that was formerly a part of IES. In addition, any nonutility activities at IBS, MERC, MGU, NSG, PGL, and WPS are included in this segment.

ITF designs, builds, maintains, owns, and/or operates compressed natural gas fueling stations in multiple states. In addition, ITF manufactures its own compressor package which includes its proprietary method of compressing natural gas.

PDI invests in distributed renewable projects, primarily solar, and owns a natural gas-fired cogeneration facility in Wisconsin, known as the Combined Locks Energy Center. Consistent with this business's strategy and focus on renewable energy projects, it is pursuing the sale of the Combined Locks Energy Center. For more information, see Note 4, Dispositions.

Fuel Supply for Generation Facilities

PDI's natural gas-fired facility is subject to market price volatility and is dispatched to produce energy only when it is economical to do so. This facility is classified as held for sale. See Note 4, Dispositions, for more information. PDI's renewable energy facilities are powered by renewable resources such as solar irradiance or landfill gas. There is no market price risk associated with the fuel supply of these facilities; however, production at these facilities can be intermittent due to the availability of the renewable energy resource.

G. ENVIRONMENTAL MATTERS

See Note 17, Commitments and Contingencies, for more information on our environmental matters.

H. 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.

I. EMPLOYEES

At December 31, 2014, our consolidated subsidiaries had the following employees:

	Number of Full-Time Employees	Total Number of Employees	Percentage of Total Employees Covered by Collective Bargaining Agreements

WPS	1,276	1,333	69	%
PGL	1,302	1,302	73	%
IBS	1,230	1,266	—	%
MERC	215	220	19	%
NSG	170	171	72	%
MGU	155	158	69	%
ITF	124	125	—	%
Total	4,472	4,575	47	%

Our consolidated subsidiaries have collective bargaining agreements with various unions which are summarized in the table below.

Union	Subsidiary	Contract Expiration Date
Local 12295 of the United Steelworkers of America, AFL CIO CLC	MGU	January 15, 2017
Local 417 of the Utility Workers Union of America, AFL CIO	MGU	February 15, 2016
Local 31 of the International Brotherhood of Electrical Workers, AFL CIO	MERC	May 31, 2016
Local 420 of the International Union of Operating Engineers	WPS	October 15, 2016
Local 18007 of the Utility Workers Union of America	PGL	April 30, 2018
Local 2285 of the International Brotherhood of Electrical Workers, AFL CIO	NSG	June 30, 2019

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 businesses, 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, including adjustments determined under riders, that our utilities 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 the costs of our utilities 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 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, distribution, and storage 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 utilities are capital intensive and require significant investments in energy generation, natural gas storage, 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 to support our utilities.

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 applicable commission may deem the additional capital costs as imprudent and disallow recovery of them through rates.

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

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 businesses 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 WPS, 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, as well as exert downward pressure on our stock price.

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 businesses that is not otherwise provided from operating cash flows and also supports our ability to provide credit support for our subsidiaries. Disruptions, uncertainty, and/or volatility in those markets could increase our cost of capital or limit the availability of capital. If we or our subsidiaries 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 businesses, cause a reduction in earnings, result in a credit rating downgrade, and/or limit our ability to sustain our current common stock dividend level.

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

We cannot be sure that any of our or our subsidiaries' 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;
- Limit the availability of adequate credit support for our subsidiaries’ operations; 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 WPS to sell electricity in the wholesale market at market prices. WPS must file an updated market power analysis with the FERC at least every three years to demonstrate it does 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 WPS possesses market power, that WPS is not charging just and reasonable rates, or that WPS has not complied with the rules required in order to maintain market-based rates, the FERC may require WPS to sell power at a price based upon the costs incurred in producing the power, or otherwise revoke or rescind its authority in that market. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates WPS 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.

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

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

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

We have 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.

We have recorded goodwill and other intangibles that could become impaired.

To the extent the value of goodwill or other intangibles becomes impaired, we have had to, and in the future, may also be required to, incur material noncash charges relating to such impairments. These impairment charges could have a material impact on our financial results.

As a holding company, we rely on the earnings of our subsidiaries to meet our financial obligations.

We are a holding company, and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our ability to meet our financial obligations and pay dividends on our common stock is dependent upon the ability of our subsidiaries to make payments to us, whether through dividends or otherwise. Our subsidiaries are separate legal entities that have no obligation to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to make payments to us depends on their earnings, cash flows, capital requirements, general financial condition, and regulatory limitations. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions, which may include requirements to maintain levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

Risks Related to the Proposed Merger with Wisconsin Energy Corporation (Wisconsin Energy)

Failure to complete the merger could negatively affect our share price and our future businesses and financial results.

Completion of the merger is not assured and is subject to risks, including the risks that approval by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, our ongoing business and financial results may be adversely affected and we will be subject to several risks, including the following:

- We may have to pay certain significant costs relating to the merger without receiving the benefits of the merger;
- The attention of our management may have been diverted to the merger rather than to our own operations and the pursuit of other opportunities that could have been beneficial to us;
- There may have been a potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;

- We would have been subject to certain restrictions on the conduct of our business which may have prevented us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger was pending;
- Our share price may decline to the extent that the current market price reflects an assumption by the market that the merger will be completed;
- There may be adverse consequences to our business and our relations with governmental agencies arising out of our efforts to obtain regulatory approvals for the merger if such efforts are unsuccessful;
- We may suffer adverse business consequences relating to the uncertainty caused by the potential merger, including a potential loss of customers; and
- We may be subject to litigation related to any failure to complete the merger.

In addition, ten purported class action and/or derivative lawsuits were filed against us, members of our board of directors, and
Wisconsin Energy. These lawsuits sought, among other things, an injunction prohibiting the consummation of the merger. As disclosed in our Form 8-K filed with the SEC on November 12, 2014, counsel for the parties to each of these lawsuits entered into a memorandum of understanding on November 12, 2014, pursuant to which, among other things, we and Wisconsin Energy agreed to make the disclosures concerning the merger that were set forth in that Form 8-K. The memorandum of understanding further provides for the dismissal with prejudice of all remaining actions and the release of any and all claims, including derivative claims, concerning the merger, subject to court approval after notice to the proposed class of our shareholders. All actions are stayed pending execution of definitive settlement documentation and a decision by the relevant courts regarding approval of the proposed settlement. While we believe the relevant courts will approve the parties' proposed settlement, we cannot make any assurances as to such approval. As discussed further below, the courts' failure to approve such settlement could result in the resumption of litigation seeking, among other things, to prevent the consummation of the merger.

The occurrence of any of these events individually or in combination could negatively affect the trading price of our common stock and our future business and financial results.

We and Wisconsin Energy may be unable to obtain the regulatory approvals required to complete the merger or, in order to do so,
we and Wisconsin Energy may be required to comply with material restrictions or conditions that may negatively affect the combined company after the merger is completed or cause us to abandon the merger.

Completion of the merger is contingent upon, among other things, the receipt of all required regulatory approvals. For us, this consists of filings with and approvals of the New York Stock Exchange (NYSE), notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the Federal Communications Commission (FCC), notice to and approval of the ICC and the MPSC, and, to the extent required, notice to and approval of the MPUC. In the case of Wisconsin Energy, this consists of filings with and approvals of the NYSE, notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the FCC, notice to and approval of the PSCW, the ICC, and the MPSC, and, if required or advisable, the MPUC. We are a party to a contested settlement agreement with the MPSC staff and all but one of the parties in the MPSC approval docket. 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 the Michigan electric distribution assets of Wisconsin Energy and WPS, 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 can provide no assurance that all required regulatory authorizations, approvals, or consents will be obtained, or that they will not contain terms, conditions, or restrictions that would be detrimental to the combined company after completion of the merger.

Uncertainties associated with the merger may cause a loss of management personnel and other key employees which could adversely affect the future business and operations of the combined company following the merger.

We and Wisconsin Energy are dependent on the experience and industry knowledge of our officers and other key employees to execute our respective business plans. The combined company's success after the merger will depend in part upon its ability to retain key management personnel and other key employees of us and Wisconsin Energy. Current and prospective employees of us and Wisconsin Energy may experience uncertainty about their future roles with the combined company following the merger, which may materially adversely affect the ability of each of us to attract and retain key personnel during the pendency of the merger. Accordingly, no assurance can be given that the combined company will be able to retain key management personnel and other key employees of us and Wisconsin Energy.

We are subject to various uncertainties and contractual restrictions while the merger is pending that could adversely affect our financial results.

Uncertainty about the effect of the merger on employees, suppliers, and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain, and motivate key personnel until the merger is completed and for a period of time thereafter. Employee retention and recruitment may be particularly challenging prior to completion of the merger, as current and prospective employees may experience uncertainty about their future roles with the combined company. 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 us and Wisconsin Energy may place a significant burden on management and internal resources. Any significant diversion of management's attention away from ongoing business, and any difficulties encountered in the transition and integration process, could affect our financial results and/or the financial results of the combined company.

In addition, the merger agreement restricts us, without Wisconsin Energy's consent, from making certain acquisitions and dispositions and taking other specified actions while the merger is pending. These restrictions may prevent us from pursuing attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

Because the merger consideration is fixed and the market price of shares of Wisconsin Energy common stock will fluctuate, our shareholders cannot be sure of the value of the merger consideration they will receive.

Upon completion of the merger, each outstanding share of our common stock will be converted into the right to receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash. Based on the closing price of Wisconsin Energy common stock on June 20, 2014, the last trading day before the public announcement of the merger, the aggregate value of the merger consideration was approximately $5.8 billion. The number of shares of Wisconsin Energy common stock to be issued pursuant to the merger agreement for each share of our common stock is fixed and will not change to reflect changes in the market price of Wisconsin Energy or our common stock. Because the exchange ratio will not be adjusted to reflect any changes in the market value of either company's common stock, the market value of the Wisconsin Energy common stock issued in connection with the merger and our common stock surrendered in connection with the merger, may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from, among other things, changes in the business, operations, or prospects of Wisconsin Energy or us prior to or following the merger; litigation or regulatory considerations; general business, market, industry, or economic conditions; and other factors both within and beyond the control of Wisconsin Energy and us. Neither we nor Wisconsin Energy is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The merger agreement precludes us from pursuing alternatives to the merger.

Under the merger agreement, we are restricted from pursuing or entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, we are restricted from, among other things, soliciting, initiating, knowingly encouraging, inducing, or knowingly facilitating a competing acquisition proposal from any person. These provisions would discourage a third party that may have an interest in acquiring all or a significant part of us from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger. As a result of these restrictions, we cannot enter into an agreement with respect to a more favorable alternative transaction, prior to the termination of the merger agreement, without incurring potentially significant liability to Wisconsin Energy.

If completed, the merger may not achieve its intended results, and we and Wisconsin Energy may be unable to successfully integrate our operations.

We and Wisconsin Energy entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, accretion to the combined company's earnings per share in the first full calendar year following completion of the merger. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including the following:

- Whether our business and the business of Wisconsin Energy can be integrated in an efficient and effective manner;
- Whether U.S. federal and state public utility authorities, whose approval is required to complete the merger, impose conditions on the completion of the merger which have an adverse effect on the combined company;
- General market and economic conditions;
- General competitive factors in the marketplace; and
- Higher than expected costs required to achieve the anticipated benefits of the merger.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees; the disruption of each company's ongoing businesses, processes, and systems; or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements. Any of these could adversely affect the combined company's ability to achieve the anticipated benefits of the merger. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results, and prospects.

Pending litigation against us and Wisconsin Energy that is the subject of a proposed settlement could nevertheless result in an injunction preventing completion of the merger, the payment of damages in the event the merger is completed, and/or may adversely affect the combined company's business, financial condition, or results of operations following the merger.

In connection with the merger, purported shareholders of ours filed putative stockholder class action and/or derivative lawsuits against us, our directors, and Wisconsin Energy seeking to enjoin the merger. As discussed above, those lawsuits are currently stayed pending finalization of proposed settlement documentation and a decision by the relevant courts regarding approval of the proposed settlement. Nevertheless, one of the conditions to the closing of the merger is that no law or judgment issued by any court of competent jurisdiction shall be in effect that, and no suit, action, or other proceeding shall be pending before any governmental entity in which such governmental entity seeks to impose any legal restraint that, prevents, makes illegal, or prohibits the consummation of the merger. Consequently, if the proposed settlement is not approved, the litigation may recommence and one of the plaintiffs may be successful in obtaining an injunction prohibiting us or Wisconsin Energy from consummating the merger on the agreed-upon terms. In that event, the injunction may prevent the merger from being completed within the expected timeframe, or at all. Furthermore, if the proposed settlement is not approved and defendants are not able to resolve these lawsuits, the lawsuits could result in substantial costs to us, including any costs associated with the indemnification of directors. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition, or results of operations.

Delays in completing the merger may substantially reduce the expected benefits of the merger.

Satisfying the conditions to, and completion of, the merger may take longer than, and could cost more than, we and Wisconsin Energy expect. Any delay in completing or any additional conditions imposed in order to complete the merger may materially adversely affect the benefits that we and Wisconsin Energy expect to achieve from the merger and the integration of our respective businesses. In addition, we or Wisconsin Energy may terminate the merger agreement if the merger is not completed by June 22, 2015, except that such date may be extended to December 22, 2015 if the only unsatisfied conditions to the completion of the merger are those regarding the receipt of required regulatory approvals.

We will incur substantial transaction fees and costs in connection with the merger.

We and Wisconsin Energy expect to incur non-recurring expenses totaling approximately $60 million in connection with the merger. Additional unanticipated costs may be incurred in the course of the integration of our businesses. We cannot be certain that the elimination of duplicative costs or the realization of other efficiencies related to the integration of the two businesses will offset the transaction and integration costs in the near term, or at all.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A. REGULATED

Natural Gas Facilities

At December 31, 2014, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,500 miles of natural gas distribution mains,
- Approximately 1,000 miles of natural gas transmission mains,
- Approximately 1.3 million natural gas lateral services,
- 296 natural gas distribution and transmission gate stations,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.2 billion-cubic-foot underground natural gas storage field located in central Illinois,*
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois, and
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquified petroleum gas.

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

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	
		Marinette, Wisconsin	Natural Gas	38.4	

	West Marinette #32				
	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	
Total 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) These facilities are jointly owned by WPS and various other utilities. The capacity indicated for each of these units is equal to WPS's portion of total plant capacity based on its percent of ownership.

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

(3) In connection with the WPS 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 17, Commitments and Contingencies, for more information regarding the Consent Decree.

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

(5) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50% ownership interest in WRPC and is entitled to 50% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 8.7 megawatts, and WPS's 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.

General

Substantially all of our utility plant at WPS, PGL, and NSG is subject to first mortgage liens.

B. HOLDING COMPANY AND OTHER

The following table summarizes information on the energy asset facilities owned by PDI and the compressed natural gas fueling stations owned by ITF as of December 31, 2014:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) [1]	
PDI					
Combined Cycle	Combined Locks	Combined Locks, Wisconsin	Natural Gas	45.5	(2)
Solar	Various	Various States	Solar Irradiance	47.3	(3)
				Length of Pipeline (Miles)	
Landfill Gas Transportation	LGS	Brazoria County, Texas	N/A	33	
				Number of Locations	
ITF					
Compressed Natural Gas (CNG)	Various	Various States	N/A	38	(4)

(1) Based on capacity ratings for summer 2015.

(2) Combined Locks has an additional five megawatts of capacity available at this facility through the lease of a steam turbine. PDI is currently pursuing the sale of Combined Locks. See Note 4, Dispositions, for more information.

(3)

The solar facilities consist of distributed solar projects ranging from 0.1 to 4.5 megawatts in size. Some of the solar facilities are wholly owned by subsidiaries of PDI and others are owned by INDU Solar Holdings, LLC, which is jointly owned by PDI and Duke Energy Generation Services. PDI's portion of solar capacity owned by INDU Solar Holdings, LLC, is 9.8 megawatts and is included in the total capacity listed.

(4) The CNG fueling stations consist of 20 stations that are wholly owned and operated by ITF. ITF operates 16 stations that are owned by AMP Trillium LLC, which is jointly owned by ITF and AMP Americas, LLC. ITF holds a 30% ownership interest in AMP Trillium LLC. Additionally, ITF operates two stations that are owned by EVO Trillium LLC, which is jointly owned by ITF and Environmental Alternative Fuels, LLC. ITF holds a 15% ownership interest in EVO Trillium LLC.

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ITEM 3. LEGAL PROCEEDINGS

Since the June 23, 2014 announcement of the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we and our board of directors, along with Wisconsin Energy, were named defendants in ten class action lawsuits and/or derivative complaints brought by purported Integrys Energy Group shareholders challenging the proposed merger. Two lawsuits were filed in the Circuit Court of Milwaukee County, Wisconsin (the "Wisconsin Court"): Amo v. Integrys Energy Group, Inc., et al., (the "Amo Action") and Inman v. Schrock, et al., (the "Inman Action"). Three lawsuits were filed in the Circuit Court of Brown County, Wisconsin: Rubin v. Integrys Energy Group, Inc., et al.; Blachor v. Integrys Energy Group, Inc., et al.; and Albera v. Integrys Energy Group, Inc., et al. (together with the Amo and Inman Actions, the "Wisconsin Actions"). Two lawsuits were filed in the Circuit Court of Cook County, Illinois: Taxman v. Integrys Energy Group, Inc., et al., and Curley v. Integrys Energy Group, Inc., et al., (the "Illinois Actions"). Three lawsuits were filed in the United States District Court for the Northern District of Illinois (the "Federal Court"): Steiner v. Budney, et al., and Collison v. Schrock, et al., (the "Steiner and Collison Actions"); and Tri-State Joint Fund v. Integrys Energy Group, Inc., et al. (the "Tri-State Action").

Each of the Wisconsin and Illinois Actions was either dismissed or consolidated with the Amo Action, and, with the exception of the Inman plaintiff, whose action was consolidated after the fact, the plaintiffs in the Wisconsin Actions joined Plaintiff Amo in filing an amended complaint on October 3, 2014. The Collison Action was consolidated with the Steiner Action.

The Wisconsin Actions and Steiner and Collison Actions allege, among other things, that members of our board breached their fiduciary duties in connection with the proposed transaction, that the merger agreement involves an unfair price, that it was the product of an inadequate sales process, that it contains unreasonable deal protection devices that purportedly preclude competing offers, that the members of our board were unjustly enriched at our expense, and that the preliminary joint proxy statement/prospectus omits material information. The complaints further variously allege that we, Wisconsin Energy, and/or its acquisition subsidiaries aided and abetted the purported breaches of fiduciary duty. The plaintiffs in these lawsuits seek, among other things, (i) a declaration that the merger agreement was entered into in breach of our directors' fiduciary duties, (ii) an injunction enjoining our board from consummating the merger, (iii) an order directing our board to exercise its duty to obtain a transaction that is in the best interests of Integrys Energy Group's shareholders, (iv) an order granting the class members any benefits allegedly improperly received by the defendants, (v) a rescission of the merger or damages, in the event that it is consummated, (vi) disgorgement of benefits or compensation obtained as a result of the purported breaches of fiduciary duty, and/or (vii) an order directing additional disclosure regarding the merger. The Tri-State Action seeks to enjoin the proposed transaction and alleges that we, our board, Wisconsin Energy, and Gale E. Klappa (the Wisconsin Energy Chief Executive Officer) violated Sections 14(a) and 20(a) of the 1934 Securities Exchange Act and Rule 14a-9 promulgated thereunder. It alleges, among other things, that the registration statement misrepresented or omitted material facts, including material information about the allegedly unfair and conflicted sales process, the inadequate consideration offered in the proposed transaction, and our actual intrinsic value.

On November 12, 2014, our counsel, our board of directors, Mr. Klappa, and Wisconsin Energy entered into a memorandum of understanding ("MOU") with counsel for plaintiffs in the Amo, Steiner and Collison, and Tri-State Actions pursuant to which we and Wisconsin Energy agreed to make additional disclosures concerning the merger. The MOU also provides that, solely for purposes of settlement, the Wisconsin Court will certify a class consisting of all persons who were record or beneficial shareholders of ours at any time between June 23, 2014 and the consummation of the merger (the "Class"). In addition, the MOU provides that, subject to approval by the Wisconsin Court after notice to the members of the Class (the "Class Members"), the Amo, Steiner and Collison, and Tri-State Actions will be dismissed with prejudice and all claims, including derivative claims, that the Class Members may possess with regard to the merger will be released. In connection with the settlement, the plaintiffs' counsel has expressed its intention to seek an award of attorneys' fees and expenses. The amount of the award to the plaintiffs' counsel will ultimately be determined by the Wisconsin and/or Federal Courts. This payment will not affect the amount of merger consideration to be received by any of our shareholders in the merger. There can be no assurance that the parties will ultimately enter into a definitive settlement agreement or that the Wisconsin Court will approve the settlement. In the absence of either event, the proposed settlement as contemplated by the MOU may be terminated.

We, our board of directors, Mr. Klappa, and Wisconsin Energy each have denied, and continue to deny, that we or they have committed or aided and abetted in the commission of any violation of law or breaches of duty or engaged in any of the alleged wrongful acts, and we, our board of directors, Mr. Klappa, and Wisconsin Energy expressly maintain that we and they diligently and scrupulously complied with fiduciary, disclosure, and other legal duties. We, our board of directors, Mr. Klappa, and Wisconsin Energy are entering into the MOU and the contemplated settlement solely to eliminate the risk, burden, and expense of further litigation. Nothing in the MOU, any settlement agreement, or any public filing shall be deemed to be an admission of the legal necessity of filing or the materiality under applicable laws of any of the additional information contained herein or in any public filing associated with the proposed settlement of the Amo, Steiner and Collison, and Tri-State Actions.

See Note 17, Commitments and Contingencies, for more information on material legal proceedings and matters related to us and our subsidiaries.

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

Common Stock and Dividend Data

Our common stock is traded on the New York Stock Exchange under the ticker symbol "TEG." The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company, LLC, 6201 15th Avenue, Brooklyn, NY 11219. The quarterly high and low sales prices for our common stock and the cash dividends per share declared for each quarter during the past two years were as follows:

	2014			2013		
Quarter	High	Low	Dividends	High	Low	Dividends
First	$59.83	$52.08	$0.68	$58.27	$52.55	$0.68
Second	71.35	56.46	0.68	62.75	55.39	0.68
Third	71.10	63.59	0.68	63.58	53.80	0.68
Fourth	80.88	64.63	0.68	59.74	52.70	0.68

As of the close of business on February 25, 2015, we had 23,107 holders of record of our common stock.

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. See Note 20, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends, as well as the dividend restrictions under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy).

Equity Compensation Plans

See Item 11, Executive Compensation, for information regarding equity securities authorized for issuance under our equity compensation plans.

Issuer Purchases of Equity Securities

The following table provides a summary of common stock purchases for the three months ended December 31, 2014:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
10/01/14 – 10/31/14 *	545,269	$69.95	—	—
11/01/14 – 11/30/14 *	540,562	72.59	—	—
12/01/14 – 12/31/14 *	267,547	75.64	—	—
Total	1,353,378	$72.13	—	—

* Represents shares of common stock purchased on the open market by American Stock Transfer & Trust Company to provide shares of common stock to participants in the Stock Investment Plan and to satisfy obligations under various stock-based employee benefit and compensation plans.

Under the merger agreement with Wisconsin Energy, we cannot issue shares of our common stock.

ITEM 6. SELECTED FINANCIAL DATA

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

As of or for Year Ended December 31 (Millions, except per share amounts, stock price, return on average equity, and number of shareholders and employees)	2014 (1) (2)		2013 (2)		2012 (2)		2011 (2)		2010 (2)	
Operating revenues	$4,144.2		$3,485.5		$3,012.9		$3,324.0		$3,392.4	
Net income from continuing operations	278.1		267.5		238.9		228.1		212.0	
Net income attributed to common shareholders	276.9		351.8		281.4		227.4		220.9	
Total assets	11,282.0		11,243.5	(3)	10,327.4		9,983.2		9,816.8	
Preferred stock of subsidiary	51.1		51.1		51.1		51.1		51.1	
Long-term debt (excluding current portion)	2,956.3		2,956.2		1,931.7		1,845.0		2,134.6	
Average shares of common stock										
Basic	80.2		79.5		78.6		78.6		77.5	
Diluted	80.7		80.1		79.3		79.1		78.0	
Earnings per common share (basic)										
Net income from continuing operations	$3.43		$3.33		$3.00		$2.86		$2.70	
Earnings per common share (basic)	3.45		4.43		3.58		2.89		2.85	
Earnings per common share (diluted)										
Net income from continuing operations	3.41		3.30		2.98		2.84		2.68	
Earnings per common share (diluted)	3.43		4.39		3.55		2.87		2.83	
Dividends per common share declared	2.72		2.72		2.72		2.72		2.72	
Stock price at year-end	$77.85		$54.41		$52.22		$54.18		$48.51	
Book value per share	$41.49		$41.05		$38.84		$38.01		$37.57	
Return on average equity	8.3	%	11.2	%	9.4	%	7.7	%	7.7	%
Number of common stock shareholders	23,511		24,908		28,425		28,993		30,352	
Number of employees	4,575		4,888		4,717		4,619		4,612	

(1) Includes the impact of the sale of UPPCO. In August 2014, we sold UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 4, Dispositions, for more information.

(2) In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC. See Note 4, Dispositions, for more information. Due to the sale, IES's retail energy business has been reclassified to discontinued operations for all periods presented.

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

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

INTRODUCTION

We are an energy holding company with natural gas and electric utility operations (serving customers in Illinois, Michigan, Minnesota, and Wisconsin), an approximate 34% equity ownership interest in ATC (a federally regulated electric transmission company), and nonregulated energy operations.

Strategic Overview

Our goal is to create long-term value for shareholders and customers through growth in our core regulated businesses.

The essential components of our business strategy are:

Maintaining and Growing a Strong Utility Base – A strong utility base is essential to maintaining a strong balance sheet, predictable cash flows, the desired risk profile, attractive dividends, and quality credit ratings. We believe the following projects have helped, or will help, maintain and grow our utility base and meet our customers' needs:

- An accelerated annual investment in natural gas distribution facilities (primarily replacement of cast iron mains) at PGL,
- WPS's proposed new natural gas-fueled electric generating unit to be built at the site of the Fox Energy Center in Wisconsin,
- WPS's continued investment in environmental projects to improve air quality and meet or exceed the requirements set by environmental regulators,
- WPS's System Modernization and Reliability Project to underground and upgrade certain electric distribution facilities in northern Wisconsin, and
- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.7 billion of transmission assets at December 31, 2014. ATC plans to invest approximately $3.3 billion to $3.9 billion in transmission system improvements during the next ten years. Although ATC's equity requirements to fund its capital investments will primarily be met by earnings reinvestment, we plan to continue to fund our share of the equity portion of future ATC growth as necessary.

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

Providing Safe, Reliable, Competitively Priced, and Environmentally Sound Energy and Related Services – Our mission is 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. This allows us to provide a safe, reliable, value-priced service for our customers. Our presence in the compressed natural gas fueling marketplace, while not currently significant, is complementary to our existing businesses and is consistent with our mission.

Integrating Resources to Provide Operational Excellence – We are committed to integrating resources of all our businesses 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 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 Asset and Risk Management – Our asset management strategy calls for the continuous assessment of existing assets, the acquisition of assets, and contractual commitments to obtain resources that complement our existing business and strategy. The goal is to provide the most efficient use of resources while maximizing return and maintaining an acceptable risk profile. This strategy focuses on acquiring assets consistent with strategic plans and disposing of assets, including property, plant, and equipment and entire business units, that are no longer strategic to ongoing operations, are not performing as intended, or have an unacceptable risk profile. We maintain a portfolio approach to risk and earnings.

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 swaps and options, provide tools to reduce the risk associated with price movement in a volatile energy market. Each business unit manages the risk profile related to these instruments consistent with our risk management policies, which are approved by the Board of Directors. The Corporate Risk Management Group, which reports through the Chief Financial Officer, provides corporate oversight.

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Natural gas utility operations	$100.2	$123.4	$93.4	(18.8)%	32.1%
Electric utility operations	163.7	110.9	107.9	47.6%	2.8%
Electric transmission investment	51.3	53.9	52.4	(4.8)%	2.9%
IES's retail operations – discontinued operations	0.4	82.5	55.1	(99.5)%	49.7%
Holding company and other operations	(38.7)	(18.9)	(27.4)	104.8%	(31.0)%
Net income attributed to common shareholders	$276.9	$351.8	$281.4	(21.3)%	25.0%
Basic earnings per share	$3.45	$4.43	$3.58	(22.1)%	23.7%
Diluted earnings per share	$3.43	$4.39	$3.55	(21.9)%	23.7%
Average shares of common stock					
Basic	80.2	79.5	78.6	0.9%	1.1%
Diluted	80.7	80.1	79.3	0.7%	1.0%

2014 Compared with 2013

The $74.9 million decrease in our earnings was driven by:

- An $82.1 million after-tax decrease in income from discontinued operations at IES. See Note 4, Dispositions, for more information.

- A $59.4 million after-tax increase in operating expenses at the utilities, excluding items directly offset in margins, driven by increases in natural gas distribution costs, depreciation and amortization expense, and electric utility maintenance.

- A $17.4 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.

- A $13.0 million increase in income tax expense due to a remeasurement of deferred income taxes in 2014 related to the sale of IES's retail energy business.

- A $9.9 million after-tax negative year-over-year impact of the 2013 reversal of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 25, Regulatory Environment, for more information.

- An $8.1 million after-tax increase in operating expenses at the holding company due to transaction costs incurred in 2014 related to the proposed merger with Wisconsin Energy Corporation.

These decreases in earnings were partially offset by:

-

A $51.2 million after-tax gain on the sale of UPPCO, net of transaction costs. See Note 4, Dispositions, for more information.

- The approximate $45 million after-tax positive impact of rate orders at the utilities.

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

- An approximate $5 million after-tax net increase in utility margins due to variances related to sales volumes, net of decoupling. A positive impact from higher sales volumes at the natural gas utilities was partially offset by a decrease in electric utility margins, driven by the sale of UPPCO at the end of August 2014.

2013 Compared with 2012

The $70.4 million increase in our earnings was driven by:

- A $41.9 million after-tax increase in income from discontinued operations. See Note 4, Dispositions, for more information.

- The approximate $30 million after-tax positive impact of rate orders at the utilities.

- An approximate $30 million after-tax increase due to an increase in sales volumes at the natural gas utilities, net of decoupling. Weather was colder than normal in 2013 and warmer than normal in 2012. In addition, certain of our natural gas utilities did not have decoupling impacts in 2012 to offset the impact of weather.

- The $9.9 million after-tax positive impact of the first quarter 2013 reversal of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 25, Regulatory Environment, for more information.

These increases were partially offset by:

- A $27.4 million after-tax increase in operating expenses at the natural gas utilities, excluding items directly offset in margins, driven by an increase in natural gas distribution costs.

- A $10.9 million after-tax increase in electric transmission expense and maintenance expense, excluding the newly acquired Fox Energy Center, at the electric utilities. The increase in maintenance expense was driven primarily by a plant outage at Weston 3.

Natural Gas Utility Segment Operations

	Year Ended December 31			Change in		Change in	
(Millions, except heating degree days)	2014	2013	2012	2014 Over 2013		2013 Over 2012	
Revenues	$2,760.4	$2,105.0	$1,672.0	31.1	%	25.9	%
Purchased natural gas costs	1,604.4	1,046.2	775.0	53.4	%	35.0	%
Margins	1,156.0	1,058.8	897.0	9.2	%	18.0	%
Operating and maintenance expense	747.3	632.7	527.5	18.1	%	19.9	%
Depreciation and amortization expense	149.0	136.0	131.8	9.6	%	3.2	%
Taxes other than income taxes	40.9	38.2	35.6	7.1	%	7.3	%
Operating income	218.8	251.9	202.1	(13.1	)%	24.6	%
Miscellaneous income	1.9	1.2	0.6	58.3	%	100.0	%
Interest expense	54.4	50.2	47.3	8.4	%	6.1	%
Other expense	(52.5)	(49.0)	(46.7)	7.1	%	4.9	%
Income before taxes	$166.3	$202.9	$155.4	(18.0	)%	30.6	%
Retail throughput in therms							
Residential	1,757.9	1,663.6	1,324.8	5.7	%	25.6	%
Commercial and industrial	586.1	534.8	406.0	9.6	%	31.7	%
Other	65.2	74.0	75.3	(11.9	)%	(1.7	)%
Total retail throughput in therms	2,409.2	2,272.4	1,806.1	6.0	%	25.8	%
Transport throughput in therms							
Residential	284.1	252.7	204.0	12.4	%	23.9	%
Commercial and industrial	1,763.4	1,650.6	1,557.9	6.8	%	6.0	%
Total transport throughput in therms	2,047.5	1,903.3	1,761.9	7.6	%	8.0	%
Total throughput in therms	4,456.7	4,175.7	3,568.0	6.7	%	17.0	%

Weather

Average actual heating degree days	7,784	7,285	5,601	6.8 %	30.1 %
Average normal heating degree days	6,764	6,600	6,709	2.5 %	(1.6)%

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. 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 approximate 43% and 7% 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 $97.2 million, driven by:

- An approximate $38 million increase in margins related to certain riders at NSG and PGL and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

NSG and PGL recovered from their customers approximately $19 million more for environmental cleanup costs at their former manufactured gas plant sites due to higher recovery rates driven by an increase in remediation costs, net of insurance settlements received, and the impact of higher sales volumes. See Note 17, Commitments and Contingencies, for more information about the manufactured gas plant sites.

NSG and PGL recovered approximately $13 million more from their customers through their bad debt rider mechanisms, driven by higher natural gas costs in 2014, an increase in sales volumes, and rate increases.

Our natural gas utilities recovered approximately $6 million more from customers for energy efficiency programs at MERC, MGU, NSG, and PGL in 2014.

- An approximate $35 million net increase in margins due to rate orders. See Note 25, Regulatory Environment, for more information.

The rate increases at NSG and PGL, effective June 27, 2013, and updated effective January 1, 2014, the impact of the Qualifying Infrastructure Plant rider at PGL, and other impacts of rate design, had an approximate $32 million positive impact on margins.

The rate increase at MGU, effective January 1, 2014, resulted in an approximate $4 million positive impact on margins.

The interim rate increase at MERC, effective January 1, 2014, had an approximate $4 million positive impact on margins.

These increases were partially offset by the approximate $5 million negative impact of WPS's 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 25, Regulatory Environment, for more information.

- An approximate $23 million net increase in margins due to sales volume variances and our decoupling mechanisms.

The combined effect of the change in weather year over year and the impact of higher weather-normalized volumes, partially offset by the impact of our decoupling mechanisms, increased margins approximately $40 million. In 2014, margins at the natural gas utilities were positively impacted by colder than normal weather, net of decoupling impacts at MERC, NSG, and PGL. Effective January 1, 2014, MGU and WPS no longer have decoupling mechanisms in place. During 2014, MERC reached its maximum accrued refund to customers under the annual 10% cap provision of its decoupling mechanism. In 2013, decoupling mechanisms were in place for all the natural gas utilities. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 25, Regulatory Environment, for more information on our decoupling mechanisms.

Margins were negatively impacted year-over-year by approximately $17 million due to a reversal in 2013 of reserves established in 2012 against PGL and NSG regulatory assets related to decoupling. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 25, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment decreased $33.1 million. This decrease was driven by a $130.3 million increase in operating expenses, partially offset by the $97.2 million increase in margins discussed above.

The increase in operating expenses was primarily due to:

- A $45.9 million increase in natural gas distribution costs, primarily at PGL. The increase in costs at PGL was driven by higher repairs and maintenance expense primarily due to higher costs to meet new compliance requirements.

- A $19.8 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. For the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $15.5 million increase in bad debt expense, driven by higher natural gas costs in 2014, an increase in sales volumes, and rate increases. The majority of the increase in bad debt expense related to PGL and NSG and had no impact on earnings since it was offset by higher rates through a rider mechanism, resulting in higher margins.

- A $13.0 million increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the AMRP at PGL. The increase was also driven by a $3.4 million reduction in expense in 2013 at MERC related to a new depreciation study approved by the MPUC on July 29, 2013, retroactive to January 1, 2012. In addition, MGU recorded a $2.5 million reduction in expense in 2013. In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010. See Note 25, Regulatory Environment, for more information.

- An $8.7 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 $5.0 million increase in workers compensation and injuries and damages expense. This increase was driven by both more severe injuries and increased incidents in 2014, primarily at PGL.

- A $4.6 million net increase in energy efficiency program expenses at our natural gas utilities. This net increase in expenses was more than offset by an approximate $6 million related increase in margins.

- A $4.0 million increase in the cost of outside services employed, primarily driven by higher consulting and contract labor costs as a result of the AMRP at PGL.

- A $3.7 million increase in unrecoverable energy efficiency program expense at MERC. In the second quarter of 2014, MERC wrote off a regulatory asset recorded for conservation improvement program costs.

- A $3.0 million increase in customer accounts expense, driven in part by higher outsourced call center costs at PGL. The increase in call center costs was primarily due to additional services provided as a result of a project to standardize the customer billing system.

- A $2.7 million increase in taxes other than income taxes, driven in part by the Illinois invested capital tax. This tax is based on an entity's equity and long-term debt balances, which have increased for PGL. Higher property taxes also contributed to the increase in expense.

- A $0.1 million net increase in employee benefit costs, driven by:

An $8.5 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 our stock price.

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, WPS deferred certain increases in pension and other employee benefit costs as a result of its 2013 rate order with the PSCW. WPS began amortizing this regulatory asset in 2014.

These increases were partially offset by a $12.7 million decrease in other employee benefit costs, primarily driven 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 18, Employee Benefit Plans, for more information on this remeasurement.

Other Expense

Other expense at the natural gas utilities increased $3.5 million. Interest expense on long-term debt increased, driven by higher average long-term debt outstanding in 2014.

2013 Compared with 2012

Margins

Natural gas utility segment margins increased $161.8 million, driven by:

- An approximate $67 million net increase in margins due to sales volume variances and our decoupling mechanisms.

The combined effect of the change in weather year over year and the impact of our decoupling mechanisms increased margins approximately $50 million. In 2012, margins at the natural gas utilities were negatively impacted by unusually warm weather, and the majority of our natural gas utilities either did not have decoupling mechanisms in place or the mechanism did not cover weather-related volume variances. In 2013, decoupling mechanisms were in place for all the natural gas utilities, but colder than normal weather did have a

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positive impact on MGU's margins as its decoupling mechanism does not cover weather-related volume variances. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 25, Regulatory Environment, for more information on our decoupling mechanisms.

In 2013, PGL and NSG recorded an increase in revenues of approximately $17 million when reserves established in 2012 against regulatory assets related to decoupling from a prior period were reversed. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 25, Regulatory Environment, for more information.

- An approximate $53 million increase in margins related to certain riders at PGL and NSG and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

Our natural gas utilities recovered approximately $27 million more from customers for energy efficiency programs at MGU, NSG, PGL, and WPS in 2013.

PGL and NSG recovered approximately $26 million more for environmental cleanup costs at their former manufactured gas plant sites related to an increase in remediation activity during 2013. See Note 17, Commitments and Contingencies, for more information about the manufactured gas plant sites.

- An approximate $31 million net increase in margins due to rate orders. See Note 25, Regulatory Environment, for more information.

The rate increases at PGL and NSG, effective June 27, 2013, and January 21, 2012, and other impacts of rate design, had an approximate $32 million positive impact on margins.

MERC recognized an approximate $2 million increase in margins primarily driven by the impact of a July 2012 rate order from the MPUC. Customer refunds were accrued in 2012 as a result of 2011 interim rates that had been in effect.

A reduction in rates at WPS, effective January 1, 2013, resulted in an approximate $3 million negative impact on margins.

- An approximate $8 million increase in margins due to the MPUC's approval of MERC's energy conservation incentives in December 2013. These financial incentives were earned by MERC for achieving certain conservation improvement program goals.

Operating Income

Operating income at the natural gas utility segment increased $49.8 million. This increase was driven by the $161.8 million increase in margins discussed above, partially offset by a $112.0 million increase in operating expenses.

The increase in operating expenses was primarily due to:

- A $31.7 million increase in energy efficiency program expenses at our natural gas utilities. Margins increased by an equal amount, resulting in no impact on earnings.

- A $28.6 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. For approximately $26 million of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $22.1 million increase in natural gas distribution costs, primarily at PGL. The increase was partially due to increased labor and contractor costs driven by additional compliance work. A portion of the compliance work was driven by new local regulations related to natural gas distribution main openings and repairs in the public way. Natural gas distribution costs also increased due to a plastic pipe fittings replacement project.

- An $8.3 million net increase in employee benefit costs. The total employee benefit costs increase of $10.4 million was primarily due to higher pension expense, largely at PGL, driven by a lower discount rate in 2013. The lower discount rate did not significantly impact the other natural gas utilities due to an increase in contributions to those plans in prior years, which increased plan assets. WPS deferred $2.1 million of certain increases in pension and other employee benefit costs that will be recovered in a future rate proceeding as a result of its 2013 rate order. See Note 25, Regulatory Environment, for more information.

- A $7.2 million increase in bad debt expense, driven by a cost of natural gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. This natural gas component is charged to customers based on actual volumes and natural gas prices. As a result of this component, bad debt expense was primarily impacted by both higher natural gas costs in 2013 and an increase in sales volumes. However, the increase in bad debt expense does not impact earnings as it is offset by higher rates through a rider mechanism, resulting in higher margins.

- A $5.2 million increase in legal and outside services expense.

- A $4.2 million net increase in depreciation and amortization expense. Continued investment in property and equipment, primarily the AMRP at PGL, drove the increase in expense. Partially offsetting the increase was a $3.4 million reduction in expense at MERC related to a new depreciation study approved by the MPUC on July 29, 2013, retroactive to January 2012. The study included changes to salvage values and costs of removal, as well as extensions to the service lives of certain assets. In addition, there was a $2.5 million reduction in expense at MGU. In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010. See Note 25, Regulatory Environment, for more information.

- A $2.7 million increase in asset usage charges from IBS, driven by new software for both natural gas management and work asset management that was placed in service during the third quarter of 2013.

- A $2.6 million increase in taxes other than income taxes, driven by the Illinois invested capital tax. This tax assessment is based on an entity's equity and long-term debt balances, which have increased for PGL in 2013.

Other Expense

Other expense at the natural gas utilities increased $2.3 million in 2013. Interest expense on long-term debt increased, driven by higher average long-term debt outstanding in 2013.

Electric Utility Segment Operations

	Year Ended December 31			Change in 2014 Over 2013	Change in 2013 Over 2012
(Millions, except degree days)	2014	2013	2012		
Revenues	$1,286.4	$1,332.1	$1,297.4	(3.4)%	2.7%
Fuel and purchased power costs	471.6	536.9	562.1	(12.2)%	(4.5)%
Margins	814.8	795.2	735.3	2.5%	8.1%
Operating and maintenance expense	445.5	440.2	405.6	1.2%	8.5%
Depreciation and amortization expense	103.0	98.6	89.0	4.5%	10.8%
Taxes other than income taxes	45.8	49.1	47.6	(6.7)%	3.2%
Gain on sale of UPPCO, net of transaction costs	(85.4)	—	—	N/A	—%
Operating income	305.9	207.3	193.1	47.6%	7.4%
Miscellaneous income	11.1	9.8	2.6	13.3%	276.9%
Interest expense	47.4	36.4	35.9	30.2%	1.4%
Other expense	(36.3)	(26.6)	(33.3)	36.5%	(20.1)%
Income before taxes	$269.6	$180.7	$159.8	49.2%	13.1%
Sales in kilowatt-hours					
Residential	3,041.9	3,132.3	3,106.6	(2.9)%	0.8%
Commercial and industrial	8,258.8	8,504.0	8,574.5	(2.9)%	(0.8)%
Wholesale	3,053.9	4,327.2	4,614.7	(29.4)%	(6.2)%
Other	35.3	37.6	38.0	(6.1)%	(1.1)%
Total sales in kilowatt-hours	14,389.9	16,001.1	16,333.8	(10.1)%	(2.0)%

Weather

WPS:					
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 %
UPPCO (sold in August 2014):					
Actual heating degree days	6,639	9,496	7,749	(30.1)%	22.5 %
Normal heating degree days	8,675	8,665	8,757	0.1 %	(1.1)%
Actual cooling degree days	122	230	335	(47.0)%	(31.3)%
Normal cooling degree days	239	232	218	3.0 %	6.4 %

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 $19.6 million, driven by:

- An approximate $41 million increase in margins related to WPS and UPPCO rate orders, effective January 1, 2014. Although the PSCW approved an electric rate decrease for WPS, 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 25, Regulatory Environment, for more information.

  Margins at WPS 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.

UPPCO's retail electric rate increase resulted in an approximate $6 million increase in margins.

Margins at WPS 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 approximately $11 million related to fuel and purchased power cost under-collections at WPS in 2014, compared with over-collections in 2013. Under the fuel rule, WPS 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 $11 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 $31 million related to sales volume variances. The decrease was primarily driven by the sale of UPPCO at the end of August 2014, which lowered margins related to sales volume variances by approximately $27 million. See Note 4, Dispositions, for more information. Margins from WPS's large commercial and industrial customers as well as residential customers also decreased, driven by lower use per customer in 2014. These decreases were partially offset by the impact of the termination of our decoupling mechanisms, effective January 1, 2014. See Note 25, Regulatory Environment, for more information. Our decoupling mechanisms did not cover large commercial and industrial customers.

Operating Income

Operating income at the electric utility segment increased $98.6 million. The increase was primarily driven by an $85.4 million net gain on the sale of UPPCO. See Note 4, Dispositions, for more information. The remaining increase in operating income was due to the $19.6 million increase in margins discussed above, partially offset by a $6.4 million increase in operating expenses.

The increase in operating expenses was driven by:

- A $13.6 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 WPS 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 $6.0 million increase in costs at WPS 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 $4.4 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. This increase is partially offset by lower depreciation driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $3.8 million increase in electric transmission expense, which is net of lower transmission costs driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

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

These increases were partially offset by:

- An $8.8 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 $27.5 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 18, Employee Benefit Plans, for more information. This decrease was partially offset by:

Higher stock-based compensation expense of $4.2 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 our stock price.

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

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

- A $3.3 million decrease in taxes other than income taxes, partially driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $2.9 million decrease in customer-related expenses. This was driven by the year-over-year change in the amortization of amounts recoverable from or refundable to customers related to energy efficiency, as well as the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $1.3 million deferral of coal shipping costs related to minimum requirements under WPS's contracts for rail obligations. WPS received approval from the PSCW in the 2014 rate order to defer these costs. This deferral was offset by a decrease in margins.

Other Expense

Other expense increased $9.7 million. The primary driver was a $13.0 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt at WPS in 2014. An increase in AFUDC of $1.8 million at WPS 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 $59.9 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. WPS's retail margins were positively impacted by the reduction in the capacity charges under the agreement, which are not included in its 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 at WPS, effective January 1, 2013. See Note 25, Regulatory Environment, for more information on the 2013 PSCW rate order.

- An approximate $10 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 WPS's decoupling mechanism was changed in 2013, and UPPCO did not have decoupling in 2012. See Note 25, Regulatory Environment, for more information.

Partially offsetting these increases was an approximate $5 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 $14.2 million. The increase was driven by the $59.9 million increase in margins discussed above, partially offset by a $45.7 million increase in operating expenses. The increase in operating expenses was driven by:

- A $14.7 million increase in maintenance expense due to a greater number of planned outages for certain WPS 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 $9.6 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 WPS's Crane Creek wind project. The reduction was the result of WPS's election to claim a Section 1603 Grant for the project in lieu of production tax credits.

- A $9.5 million increase in electric transmission expense.

- A $5.6 million increase due to WPS's deferral of the net difference between actual and rate case-approved costs resulting from the purchase of Fox Energy Company LLC. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, WPS did receive approval from the PSCW to defer ownership costs above or below its 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 WPS's 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 $4.7 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 the WPS 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.

Electric Transmission Investment Segment Operations

	Year Ended December 31			Change in 2014	Change in 2013
(Millions)	2014	2013	2012	Over 2013	Over 2012
Earnings from equity method investments	$85.7	$89.1	$85.3	(3.8)%	4.5%

2014 Compared with 2013

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment decreased $3.4 million. The decrease resulted from lower earnings related to our approximate 34% ownership interest in ATC. In 2014, ATC recorded a reserve for an anticipated refund to customers related to a complaint filed with FERC requesting a lower return on equity for certain transmission owners. The reserve reduced our earnings from ATC by $6.6 million.

2013 Compared with 2012

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $3.8 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

Holding Company and Other Segment Operations

(Millions)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Operating loss	$(17.7)	$(19.7)	$(15.7)	(10.2)%	25.5 %
Other expense	(32.4)	(27.5)	(28.0)	17.8 %	(1.8)%
Loss before taxes	$(50.1)	$(47.2)	$(43.7)	6.1 %	8.0 %

2014 Compared with 2013

Operating Loss

Operating loss at the holding company and other segment decreased $2.0 million. The improvement was driven by a $5.0 million gain on the abandonment of PDI's Winnebago Energy Center, as well as a $4.6 million decrease in operating losses at ITF. Also contributing to the decrease was a $2.7 million increase in operating income at IBS driven by an increase in its return on capital charged to the utilities. Partially offsetting these decreases were $10.4 million of transaction costs recorded in 2014 related to the proposed merger with Wisconsin Energy Corporation.

Other Expense

Other expense at the holding company and other segment increased $4.9 million. The increase was primarily due to an $11.0 million increase in interest expense on long-term debt, driven by the issuance of $400.0 million of Junior Subordinated Notes in August 2013. This increase was partially offset by a $3.5 million gain on the sale of land at the holding company, as well as a $2.0 million unrealized gain recorded on exchange-traded funds in 2014. In July 2014, exchange-traded funds previously held by IBS were transferred to the rabbi trust at the holding company. See Note 18, Employee Benefit Plans, for more information. Prior to July 2014, the unrealized gains (losses) on these investments were allocated to the other operating segments.

2013 Compared with 2012

Operating Loss

Operating loss at the holding company and other segment increased $4.0 million. Included in this amount is a $2.0 million increase in operating losses at ITF, as well as miscellaneous items at the holding company.

Other Expense

Other expense at the holding company and other segment decreased $0.5 million. The decrease was driven by $4.0 million of excise tax credits recorded at ITF in 2013 as a result of the American Taxpayer Relief Act of 2012, partially offset by a $2.1 million increase in interest expense, driven by the issuance of $400.0 million of Junior Subordinated Notes during August 2013.

Provision for Income Taxes

	Year Ended December 31 2014	2013	2012
Effective Tax Rate	41.0 %	37.1 %	33.0 %

2014 Compared with 2013

Our effective tax rate increased in 2014. This increase was primarily due to a $13.0 million expense caused by the remeasurement of deferred taxes related to the sale of IES's retail energy business.

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 WPS's 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, our effective tax rate was also lowered by the effective settlement of certain state income tax examinations and remeasurements of uncertain tax positions included in our liability for unrecognized tax benefits. We decreased our provision for income taxes by $8.1 million in 2012, primarily related to these items. We also decreased our provision for income taxes by $5.9 million in 2012 as a result of WPS's 2013 rate case settlement agreement. WPS 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 25, Regulatory Environment, for more information.

The increase in the effective tax rate was partially offset by a $3.7 million reduction in the provision for income taxes in 2013 due to the reversal of a regulatory liability. Deferred income taxes that had been recorded in prior years were reversed as a result of the treatment of scheduled income tax rate changes in Illinois in our final 2013 rate order.

For information on changes in the deferred income tax balances, see Note 16, Income Taxes.

Discontinued Operations

(Millions)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Discontinued operations, net of tax	$1.8	$87.3	$45.4	(97.9)%	92.3%

2014 Compared with 2013

Earnings from discontinued operations, net of tax, decreased $85.5 million in 2014. These lower earnings were primarily driven by a decrease of $82.1 million related to the operations of IES's retail energy business, which was sold in November 2014. Included in this amount was a $46.6 million after-tax decrease in net unrealized gains on derivative contracts. In addition, we realized a $17.3 million after-tax loss on the sale in November 2014. See Note 4, Dispositions, for more information.

2013 Compared with 2012

Earnings from discontinued operations, net of tax, increased $41.9 million in 2013. These higher earnings were primarily driven by an increase of $27.4 million related to the operations of IES's retail energy business, which was sold in November 2014. See Note 4, Dispositions, for more information. In 2013 and 2012, we also remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. Discontinued operations increased $4.1 million as a result of these remeasurements. Finally, in 2012, we recognized after-tax losses from discontinued operations of $6.9 million related to WPS Westwood Generation, LLC (Westwood) and $4.0 million related to WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse). We sold Westwood in November 2012 and Beaver Falls and Syracuse in March 2013. These losses were partially driven by the $5.7 million of after-tax impairment losses related to Westwood, Beaver Falls, and Syracuse recognized in 2012 when the generation facilities met the criteria for discontinued operations. See Note 4, Dispositions, for more information.

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 equity and 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 $601.4 million, compared with $554.9 million during 2013. The $46.5 million increase in net cash provided by operating activities was driven by:

- A $1,538.6 million increase in cash collections from customers, mainly due to rate increases at the utilities, higher commodity prices, an increase in electric wholesale revenues, and colder weather in 2014. Included in the electric utility 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 WPS's early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

- A $27.0 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.

These increases in cash were partially offset by:

- A $1,274.2 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 $159.7 million decrease in cash due to increased operating and maintenance costs in 2014. The increase in operating and maintenance costs was driven by higher natural gas distribution costs at PGL related to compliance activities, higher electric utility maintenance from planned major outages at WPS, and other higher WPS costs associated with owning and operating the Fox Energy Center beginning in March 2013.

- A $48.8 million decrease in cash driven by lower collateral requirements at IES in 2014. We sold IES's retail energy business in November 2014.

- A $31.8 million increase in contributions to pension and other postretirement benefit plans.

- A $30.7 million increase in cash paid for interest, primarily driven by higher average outstanding long-term debt in 2014.

- An $11.1 million decrease in cash received for income taxes, partially driven by cash paid for income taxes related to the gain on the sale of UPPCO in August 2014. This decrease in cash was partially offset by a federal income tax refund received in the first quarter of 2014 for an amended return.

- A $9.0 million decrease in cash from various deferrals at WPS, 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 $5.4 million increase in cash used for environmental remediation activities.

2013 Compared with 2012

During 2013, net cash provided by operating activities was $554.9 million, compared with $573.8 million million during 2012. The $18.9 million decrease in net cash provided by operating activities was largely driven by:

- A $74.9 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 $50.0 million payment in 2013 for WPS's early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

- A $42.8 million decrease in cash received from income taxes, primarily driven by a federal income tax refund received in 2012 for a net operating loss incurred in 2010 that was carried back to a prior year. The 2010 net operating loss was driven by bonus tax depreciation.

- A $34.3 million decrease in cash related to customer prepayments and credit balances due to higher natural gas prices and higher sales volumes in 2013.

- A $24.2 million decrease in cash at PGL and NSG due to natural gas cost under-collection activity with customers in 2013 versus natural gas cost over-collection activity with customers in 2012. The year-over-year change was driven by higher natural gas prices and higher sales volumes in 2013.

- A $7.3 million decrease in cash year-over-year driven by lower collateral requirements in 2012 at IES. Collateral requirements are based on forward positions with counterparties.

These decreases in cash were partially offset by:

- A $210.9 million decrease in contributions to pension and other postretirement benefit plans.

- A $9.5 million increase in cash from a settlement received by IES related to certain Seams Elimination Charge Adjustment payments made in prior years to a transmission provider.

Investing Cash Flows

2014 Compared with 2013

During 2014, net cash used for investing activities was $336.5 million, compared with $1,022.7 million during 2013. The $686.2 million decrease in net cash used for investing activities was primarily due to:

- The positive year-over-year impact of cash used to purchase two businesses in 2013. WPS purchased Fox Energy Company LLC for $391.6 million, and IES purchased Compass Energy Services for $15.7 million in 2013. See Note 3, Acquisitions, for more information on the Fox Energy Company LLC acquisition.

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- The receipt of proceeds of $336.5 million in 2014 related to the sale of UPPCO. See Note 4, Dispositions, for more information.

- The receipt of proceeds of $311.6 million in 2014 related to the sale of IES. See Note 4, Dispositions, for more information.

These decreases in cash used were partially offset by:

- A $195.8 million increase in cash used for capital expenditures other than the Fox Energy Center acquisition discussed above.

- A $115.5 million increase in cash used due to the required funding of the rabbi trust for deferred compensation and certain nonqualified pension plans. The proposed merger with Wisconsin Energy Corporation qualified as a potential change in control event under the rabbi trust agreement, which required the funding of the rabbi trust. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information about the merger.

- 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.

2013 Compared with 2012

During 2013, net cash used for investing activities was $1,022.7 million, compared with $602.6 million during 2012. The $420.1 million increase in net cash used for investing activities was primarily due to $391.6 million of cash used in 2013 for WPS's purchase of Fox Energy Company LLC. IES also purchased Compass Energy Services, which increased net cash used for investing activities by $15.7 million. See Note 3, Acquisitions, for more information regarding these purchases. Also contributing to the increase was a $74.8 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 WPS's 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
Natural gas utility	$456.5	$370.0	$375.1	$86.5	$(5.1)
Electric utility	286.6	615.0	163.9	(328.4)	451.1
IES	0.9	2.6	2.0	(1.7)	0.6
Holding company and other	121.0	73.2	53.4	47.8	19.8
Integrys Energy Group consolidated	$865.0	$1,060.8	$594.4	$(195.8)	$466.4

2014 Compared with 2013

The increase in capital expenditures at the natural gas utility segment was primarily due to work on the AMRP at PGL. Capital expenditures related to distribution, transmission, and natural gas storage also contributed to the increase.

The decrease in capital expenditures at the electric utility segment was primarily due to WPS's 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 holding company was due to increased expenditures for software projects and office leasehold improvements.

2013 Compared with 2012

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

The increase in capital expenditures at the holding company and other segment was primarily due to increased software project expenditures, partially offset by a decrease in solar investments.

Financing Cash Flows

2014 Compared with 2013

During 2014, net cash used for financing activities was $269.2 million, compared with net cash provided by financing activities of $462.7 million during 2013. The $731.9 million year-over-year negative impact from financing activities was driven by:

- A $785.5 million net decrease in cash due to a $974.0 million decrease in the issuance of long-term debt, which was partially offset by a $188.5 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 $140.9 million increase in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. We began purchasing shares of our common stock on the open market starting in February 2014 as well as for a short period during the first quarter of 2013.

These decreases in cash were partially offset by:

- A $148.0 million increase in cash due to lower net repayments of commercial paper in 2014.

- A $47.1 million increase in cash due to higher stock option exercises in 2014.

2013 Compared with 2012

During 2013, net cash provided by financing activities was $462.7 million, compared with $28.1 million during 2012. The $434.6 million increase in cash provided by financing activities was driven by:

- A $687.7 million net increase in cash due to a $746.0 million increase in the issuance of long-term debt, which was partially offset by an $58.3 million increase in the repayment of long-term debt. The issuance of long-term debt in 2013 included replacing WPS's borrowing of $200.0 million under its 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.

- An $87.9 million decrease in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. We began issuing new shares to meet these obligations in February 2013.

These increases were partially offset by a $335.5 million decrease in cash from $156.4 million of net repayments of commercial paper in 2013, compared with $179.1 million of net borrowings in 2012.

Significant Financing Activities

The following table provides a summary of common stock activity to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans.

Period	Method of meeting requirements
Beginning 02/05/2014	Purchasing shares on the open market
02/05/2013 – 02/04/2014	Issued new shares
01/01/2012 – 02/04/2013	Purchased shares on the open market

Under the merger agreement with Wisconsin Energy Corporation, we cannot issue shares of our common stock.

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

For information on long-term debt, see Note 14, Long-Term Debt.

Credit Ratings

Our current credit ratings and the credit ratings for WPS, PGL, and NSG are listed in the table below:

Credit Ratings	Standard & Poor's	Moody's
Integrys Energy Group		
Issuer credit rating	A-	N/A
Senior unsecured debt	BBB+	A3
Commercial paper	A-2	P-2
Junior subordinated notes	BBB	Baa1
WPS		
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
PGL		
Issuer credit rating	A-	A2
Senior secured debt	N/A	Aa3
Commercial paper	A-2	P-1
NSG		
Issuer credit rating	A-	A2

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 September 18, 2014, Moody's raised the senior unsecured debt rating to "A3" from "Baa1" and the junior subordinated notes rating to "Baa1" from "Baa2" for Integrys Energy Group. The upgrade in ratings reflected Moody's view that the sale of the IES retail energy business will markedly improve our business risk profile and result in more reliable and stable operating cash flows going forward from our utility operations.

On January 31, 2014, Moody's confirmed the credit ratings for Integrys Energy Group and raised the credit ratings for WPS, PGL, and NSG. The issuer rating was raised to "A1" from "A2" for WPS and to "A2" from "A3" for both PGL and NSG. WPS's first mortgage bonds rating was raised to "Aa2" from "Aa3." The senior secured debt rating was raised to "Aa2" from "Aa3" for WPS and to "Aa3" from "A1" for PGL. The preferred stock rating for WPS was raised to "A3" from "Baa1." Finally, PGL's commercial paper rating was raised to "P-1" from "P-2." The upgrade in ratings of the utilities reflects Moody's views of the regulatory provisions in Wisconsin and Illinois 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 subsidiaries:

	Payments Due By Period				
(Millions)	Total Amounts	2015	2016 to 2017	2018 to 2019	Later Years

	Committed				
Long-term debt principal and interest payments [1]	$ 7,414.9	$273.6	$503.3	$336.0	$6,302.0
Operating lease obligations	73.4	4.7	10.8	10.3	47.6
Energy and transportation purchase obligations [2]	1,722.2	374.7	463.9	285.0	598.6
Purchase orders [3]	981.7	885.3	94.4	2.0	—
Pension and other postretirement funding obligations [4]	44.6	17.8	26.8	—	—
Capital contributions to equity method investment	1.7	1.7	—	—	—
Total contractual cash obligations	$ 10,238.5	$1,557.8	$1,099.2	$633.3	$6,948.2

(1) Represents bonds and notes issued, as well as loans made to us and our subsidiaries. We record all principal obligations on the balance sheet. For purposes of this table, it is assumed that the current interest rates on variable rate debt will remain in effect until the debt matures.

(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 proposed merger with Wisconsin Energy Corporation qualified as a potential change in control event under the rabbi trust agreement and triggered the full funding of our deferred compensation obligation and our obligation for certain nonqualified pension plans. As a result, obligations of $7.0 million will be funded through a transfer of assets from the rabbi trust for certain nonqualified pension plans in 2015.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $579.7 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 17, Commitments and Contingencies, for more information about environmental liabilities. The table also does not reflect estimated future payments for the December 31, 2014 liability of $2.7 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 16, Income Taxes, for more information about unrecognized tax benefits.

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
Natural Gas Utility				
Distribution, transmission, and underground storage facilities	$498	$505	$493	$1,496
Other projects	29	25	30	84
Electric Utility				
Distribution and energy supply operations projects	171	306	397	874
Environmental projects	171	*42	*23	236
Other projects	7	3	3	13
Holding Company and Other				
Renewable energy projects	40	40	40	120
Corporate or shared services software and infrastructure projects	39	28	36	103
Compressed natural gas fueling stations	28	29	30	87
Total capital expenditures	$983	$978	$1,052	$3,013

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

We expect to provide capital contributions to ATC (not included in the above table) of approximately $53 million from 2015 through 2017.

All projected capital and investment 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, acquisition and development opportunities, 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), dividends from our subsidiaries, and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

Under an existing shelf registration statement, we may issue debt, equity, certain types of hybrid securities, and other financial instruments with amounts, prices, and terms to be determined at the time of future offerings. However, under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we cannot issue shares of our common stock.

WPS currently has a shelf registration statement under which it 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 with Wisconsin Energy, WPS and PGL cannot issue long-term debt in excess of $300 million and $250 million, respectively, in 2015 without Wisconsin Energy's approval.

We reduced the size of our credit facilities by $350 million during the fourth quarter of 2014 due to the sale of IES. We expect to reduce the credit facilities further in 2015 as the remaining credit support at IES is fully transferred to Exelon Generation Company, LLC.

At December 31, 2014, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 13, Short-Term Debt and Lines of Credit, for more information on credit facilities and other short-term credit agreements. See Note 14, Long-Term Debt, for more information on long-term debt.

Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our utility subsidiaries to transfer funds to us in the form of dividends. Our utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 20, Common Equity, for more information on dividend restrictions.

Other Future Considerations

Potential Addition of an Electric Generator at the Fox Energy Center Site

In 2013, WPS announced a need for an additional 400 to 500 megawatts (MW) of electric generating capacity by 2019 to meet the energy needs of its customers. After evaluating various options, WPS proposed building a new 400-MW natural gas-fired, combined-cycle generating unit for approximately $517 million to be located at its Fox Energy Center site. In January 2015, WPS 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 Resource (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 WPS, 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 us (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 WPS 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 were no material SSR costs for WPS 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 WPS's 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 us. 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 WPS, 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 the WPS electric distribution assets is contingent upon the close of the merger between Wisconsin Energy and us. See Note 2, Proposed Merger 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 earnings 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 $6.6 million pretax reduction for 2014.

Wisconsin Fuel Rule Under-collection "Cap"

WPS uses a "fuel window" mechanism to recover fuel and purchased power costs for its 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 WPS 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 WPS in 2014.

Decoupling

In 2012, the Illinois Attorney General and Citizens Utility Board appealed the ICC's authority to approve PGL's and NSG's permanent decoupling mechanism. As a result, revenues collected under this mechanism were potentially subject to refund. In 2012, PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Illinois Appellate Court affirmed the ICC's authority to approve the permanent decoupling mechanism. Therefore, the reserves recorded in 2012 were reversed in the first quarter of 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Court's decision. In January 2015, the Illinois Supreme Court affirmed the ICC's authority to approve the permanent decoupling mechanism. As a result, decoupling amounts recorded in 2014 will be refunded to customers in 2015 as planned, and decoupling amounts in the future will continue to be accrued.

See Note 25, Regulatory Environment, for more information on all of our subsidiaries' decoupling mechanisms.

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 WPS 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.

The majority 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 this area 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 22, 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.

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2014. No impairments were recorded as a result of these tests. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. 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 a reporting unit. For the regulated reporting units, 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 of these reporting units to decrease.

Key assumptions used in the income approach included return on equity (ROE) for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is determined based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is based on its 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 for each utility service area.

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 for the utility reporting units to determine indications 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.

The fair values of the WPS natural gas utility and ITF reporting units exceeded the carrying values by a substantial amount. Based on these results, these reporting units are not at risk of failing step one of the goodwill impairment test.

The fair values calculated in the first step of the test for MERC, MGU, NSG, and PGL exceeded the carrying values by approximately 4% to 18%. Due to the subjectivity of the assumptions and estimates underlying the impairment analyses, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, which would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test. Failing step one would result in a goodwill impairment that could be material, as the carrying value of the identifiable assets and liabilities is considered fair value for regulated companies. This is because a regulator would typically not allow the assets and liabilities of a regulated company to be increased or decreased, allowing for a change in recovery from ratepayers, as a result of an acquisition or other change in ownership. If the carrying value exceeds the calculated fair value of the reporting unit, the excess would be recorded as a goodwill impairment.

Change in Key Inputs (in basis points)	MERC	MGU	NSG	PGL
Discount rate	175	25	75	150
Terminal year return on equity	(440)	(138)	(248)	(428)
Terminal year growth rate	(200)	(50)	(50)	N/A *

* Even with a terminal year growth rate of 0%, assuming all other inputs remained constant, PGL would still have passed the first step of the goodwill impairment test.

In June 2014, IES performed an interim goodwill impairment analysis. This interim analysis was triggered by the announcement of the plan to sell IES's retail energy business. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss of $6.7 million in the second quarter of 2014. In November 2014, IES's retail energy business was sold to Exelon Generation Company, LLC. See Note 4, Dispositions, for more information.

Our goodwill balances by reporting unit were as follows at December 31, 2014:

(Millions, except percentages)	Goodwill	Percentage of Total Goodwill
PGL	$401.2	61.2 %
MERC	127.6	19.5 %
WPS's natural gas utility	36.4	5.5 %
NSG	36.1	5.5 %
MGU	34.5	5.3 %
ITF	19.6	3.0 %
Total goodwill	$655.4	100.0 %

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. At December 31, 2014, and 2013, our unbilled revenues were $269.4 million and $286.4 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 18, 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 at the utility segments 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)	$117.7	$8.9
Discount rate	0.5	(104.3)	(7.1)
Rate of return on plan assets	(0.5)	N/A	7.0
Rate of return on plan assets	0.5	N/A	(7.0)

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)	$32.6	$2.7
Discount rate	0.5	(28.4)	(3.3)
Health care cost trend rate	(1.0)	(51.4)	(8.6)
Health care cost trend rate	1.0	61.7	8.7
Rate of return on plan assets	(0.5)	N/A	2.1
Rate of return on plan assets	0.5	N/A	(2.1)

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 6.3%, 15.1%, and 14.3%, 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 the following approaches by plan. For plans sponsored by IBS and WPS, we use the calculated value approach. For plans sponsored by PELLC, we use the fair market 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 WPS. However, for plans sponsored by IBS and PELLC, only differences between actual investment returns and the 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 18, Employee Benefit Plans.

Regulatory Accounting

Our natural gas and electric 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 these utilities. 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 natural gas and electric 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 natural gas and electric 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 14.5% decrease in total assets and a 7.0% decrease in total liabilities. The two largest regulatory assets at December 31, 2014, are related to environmental remediation costs and unrecognized pension and other postretirement benefit costs. A write-off of the regulatory asset related to environmental remediation costs at December 31, 2014, would result in a 5.6% decrease in total assets. A write-off of the unrecognized pension and other postretirement benefit related regulatory asset at December 31, 2014, would result in a 4.5% decrease in total assets. See Note 9, 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(r), Income Taxes, and Note 16, 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 our regulated operations are not recovering the effects of inflation, they will file rate cases as necessary in the various jurisdictions in which they operate. Our nonregulated businesses include inflation in forecasted costs, which impacts product pricing.

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 are also exposed to other significant risks due to the nature of our subsidiaries' businesses and the environment in which we operate. 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 the wholesale electric operations and Michigan retail electric operations of WPS. Prudently incurred costs of natural gas used by the natural gas utilities are also recovered from customers under one-for-one recovery mechanisms. These recovery mechanisms greatly reduce commodity price risk for the utilities.

WPS's 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(f), Revenues and Customer Receivables, for more information.

To manage commodity price risk for their customers, the utilities enter into fixed-price contracts of various durations for the purchase and/or sale of natural gas, fuel for electric generation, and electricity. They also employ risk management techniques, which include the use of derivative instruments such as swaps, futures, and options.

Interest Rate Risk

We are exposed to interest rate risk resulting from our short-term borrowings and projected near-term debt financing needs. We manage exposure to interest rate risk by limiting the amount of our variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at December 31, 2014, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.2 million. Comparatively, based on the variable rate debt outstanding at December 31, 2013, an increase in interest rates of 100 basis points would have increased annual interest expense by $3.3 million. 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. Most of our employee benefit costs relate to the utilities. As such, the majority of these costs are recovered in customers' rates, reducing most of 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

The management of Integrys Energy Group and our subsidiaries 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.

Our independent registered public accounting firm has issued an audit report on the effectiveness of our internal control over financial reporting.

B. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Integrys Energy Group, Inc. and subsidiaries 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

March 2, 2015

C. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 (Millions, except per share data)	2014	2013	2012
Operating revenues	$4,144.2	$3,485.5	$3,012.9
Cost of sales	2,133.0	1,598.7	1,349.1
Operating and maintenance expense	1,199.7	1,086.7	943.0
Depreciation and amortization expense	287.5	263.4	247.3
Taxes other than income taxes	97.0	97.2	94.0
Merger transaction costs	10.4	—	—
Gain on sale of UPPCO, net of transaction costs	(85.4)	—	—
Gain on abandonment of PDI's Winnebago Energy Center	(5.0)	—	—
Operating income	507.0	439.5	379.5
Earnings from equity method investments	88.3	91.5	87.2
Miscellaneous income	31.0	21.9	9.0
Interest expense	154.8	127.4	118.9
Other expense	(35.5)	(14.0)	(22.7)
Income before taxes	471.5	425.5	356.8
Provision for income taxes	193.4	158.0	117.9
Net income from continuing operations	278.1	267.5	238.9
Discontinued operations, net of tax	1.8	87.3	45.4
Net income	279.9	354.8	284.3
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.1	0.2
Net income attributed to common shareholders	$276.9	$351.8	$281.4
Average shares of common stock			
Basic	80.2	79.5	78.6
Diluted	80.7	80.1	79.3
Earnings per common share (basic)			
Net income from continuing operations	$3.43	$3.33	$3.00
Discontinued operations, net of tax	0.02	1.10	0.58
Earnings per common share (basic)	$3.45	$4.43	$3.58
Earnings per common share (diluted)			
Net income from continuing operations	$3.41	$3.30	$2.98
Discontinued operations, net of tax	0.02	1.09	0.57
Earnings per common share (diluted)	$3.43	$4.39	$3.55

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

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D. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (Millions)	2014	2013	2012
Net income	$279.9	$354.8	$284.3
Other comprehensive income (loss), net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of an insignificant amount for all periods presented	—	0.7	(0.2)
Reclassification of net losses (gains) to net income, net of tax of $1.2 million, $3.6 million, and $2.0 million, respectively	(0.1)	1.4	6.5
Cash flow hedges, net	(0.1)	2.1	6.3
Defined benefit plans			
Pension and other postretirement benefit adjustments arising during period, net of tax of $(3.0) million, $8.9 million, and $(4.4) million, respectively	(6.0)	13.2	(6.1)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.8 million, $1.7 million, and $1.0 million, respectively	1.7	2.4	1.4
Defined benefit plans, net	(4.3)	15.6	(4.7)
Other comprehensive income (loss), net of tax	(4.4)	17.7	1.6
Comprehensive income	275.5	372.5	285.9
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.1	0.2
Comprehensive income attributed to common shareholders	$272.5	$369.5	$283.0

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

E. CONSOLIDATED BALANCE SHEETS

At December 31 (Millions, except share and per share data)	2014	2013
Assets		
Cash and cash equivalents	$18.0	$16.8
Accounts receivable and accrued unbilled revenues, net of reserves of $63.3 and $47.7, respectively	699.8	646.1
Inventories	327.2	218.9
Regulatory assets	118.9	127.4
Assets held for sale	0.7	277.9
Assets of discontinued operations related to IES's retail energy business	—	815.4
Deferred income taxes	52.4	31.4
Prepaid taxes	136.2	144.4
Other current assets	57.5	55.9
Current assets	1,410.7	2,334.2
Property, plant, and equipment, net of accumulated depreciation of $3,343.1 and $3,221.0, respectively	6,859.8	6,206.2
Regulatory assets	1,513.6	1,361.4
Equity method investments	572.4	540.9
Goodwill	655.4	655.4
Other long-term assets	270.1	145.4
Total assets	$11,282.0	$11,243.5
Liabilities and Equity		
Short-term debt	$317.6	$326.0
Current portion of long-term debt	125.0	100.0
Accounts payable	490.7	401.9
Accrued taxes	87.7	78.9
Regulatory liabilities	153.7	101.1
Liabilities held for sale	—	49.1
Liabilities of discontinued operations related to IES's retail energy business	—	447.5
Other current liabilities	261.4	218.9
Current liabilities	1,436.1	1,723.4
Long-term debt	2,956.3	2,956.2
Deferred income taxes	1,570.0	1,390.3
Deferred investment tax credits	65.5	57.6
Regulatory liabilities	399.9	383.7
Environmental remediation liabilities	579.9	600.0
Pension and other postretirement benefit obligations	274.6	200.8
Asset retirement obligations	480.2	491.0
Other long-term liabilities	168.7	127.1
Long-term liabilities	6,495.1	6,206.7
Commitments and contingencies		
	80.0	79.9

Common stock – $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,534,171 shares outstanding		
Additional paid-in capital	2,642.2	2,660.5
Retained earnings	626.0	567.1
Accumulated other comprehensive loss	(27.6)	(23.2)
Shares in deferred compensation trust	(20.9)	(23.0)
Total common shareholders' equity	3,299.7	3,261.3
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding	51.1	51.1
Noncontrolling interest in subsidiaries	—	1.0
Total liabilities and equity	$11,282.0	$11,243.5

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

F. CONSOLIDATED STATEMENTS OF EQUITY

(Millions, except per share data)	Integrys Energy Group Common Shareholders' Equity Shares in Deferred Compen-sation Trust	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interest in Subsidiaries	Total Equity
Balance at December 31, 2011	$(17.1)	$78.3	$2,579.1	$363.6	$(42.5)	$2,961.4	$51.1	$0.1	$3,012.6
Net income attributed to common shareholders	—	—	—	281.4	—	281.4	—	(0.2)	281.2
Other comprehensive income	—	—	—	—	1.6	1.6	—	—	1.6
Stock-based compensation	—	—	(4.1)	(0.7)	—	(4.8)	—	—	(4.8)
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(211.9)	—	(211.9)	—	—	(211.9)
Shares purchased for the deferred compensation trust	(3.2)	—	—	—	—	(3.2)	—	—	(3.2)
Other	2.6	—	(0.4)	(0.9)	—	1.3	—	—	1.3
Balance at December 31, 2012	$(17.7)	$78.3	$2,574.6	$431.5	$(40.9)	$3,025.8	$51.1	$(0.1)	$3,076.8
Net income attributed to common shareholders	—	—	—	351.8	—	351.8	—	(0.1)	351.7
Other comprehensive income	—	—	—	—	17.7	17.7	—	—	17.7
Issuance of common stock	—	1.5	78.3	—	—	79.8	—	—	79.8
Stock-based compensation	—	—	1.0	(0.7)	—	0.3	—	—	0.3
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(214.6)	—	(214.6)	—	—	(214.6)

Net contributions from noncontrolling parties	—	—	—	—	—	—	—	1.0	1.0
Shares issued to the deferred compensation trust	(6.3)	0.1	6.2	—	—	—	—	—	—
Other	1.0	—	0.4	(0.9)	—	0.5	—	0.2	0.7
Balance at December 31, 2013	$(23.0)	$79.9	$2,660.5	$567.1	$(23.2)	$3,261.3	$51.1	$1.0	$3,313.4
Net income attributed to common shareholders	—	—	—	276.9	—	276.9	—	(0.1)	276.8
Other comprehensive loss	—	—	—	—	(4.4)	(4.4)	—	—	(4.4)
Issuance of common stock	—	0.1	2.3	—	—	2.4	—	—	2.4
Stock-based compensation	—	—	(20.9)	(0.8)	—	(21.7)	—	—	(21.7)
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(216.3)	—	(216.3)	—	—	(216.3)
Shares purchased for the deferred compensation trust	(0.6)	—	—	—	—	(0.6)	—	—	(0.6)
Other	2.7	—	0.3	(0.9)	—	2.1	—	(0.9)	1.2
Balance at December 31, 2014	$(20.9)	$80.0	$2,642.2	$626.0	$(27.6)	$3,299.7	$51.1	$ —	$3,350.8

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

G. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31			
(Millions)	2014	2013	2012
Operating Activities			
Net income	$279.9	$354.8	$284.3
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization expense	290.2	266.6	252.5
Recoveries and refunds of regulatory assets and liabilities	42.6	44.3	49.9
Net unrealized gains on energy contracts	(21.4)	(100.5)	(34.6)
Bad debt expense	51.6	34.4	26.2
Pension and other postretirement expense	19.0	62.1	62.3
Pension and other postretirement contributions	(108.8)	(77.0)	(287.9)
Deferred income taxes and investment tax credits	165.9	209.8	146.0
Gain on sale of UPPCO	(86.5)	—	—
Loss on sale of IES's retail energy business	24.3	—	—
Gain on sale or disposal of other assets	(15.2)	(1.8)	(2.7)
Equity income, net of dividends	(13.3)	(19.2)	(17.5)
Termination of tolling agreement with Fox Energy Company LLC	—	(50.0)	—
Other	43.5	34.9	25.3
Changes in working capital			
Collateral on deposit	(46.5)	2.3	9.6
Accounts receivable and accrued unbilled revenues	11.2	(358.6)	(26.2)
Inventories	(124.4)	16.8	28.9
Other current assets	(11.6)	(50.4)	6.6
Accounts payable	12.7	142.9	21.8
Other current liabilities	88.2	43.5	29.3
Net cash provided by operating activities	601.4	554.9	573.8
Investing Activities			
Capital expenditures	(865.0)	(669.2)	(594.4)
Proceeds from the sale of UPPCO, net of cash divested	336.5	—	—
Proceeds from the sale of IES's retail energy business, net of cash divested	311.6	—	—
Proceeds from the sale or disposal of other assets	26.1	6.6	17.0
Capital contributions to equity method investments	(18.4)	(13.7)	(27.4)
Rabbi trust funding related to potential change in control	(115.5)	—	—
Acquisition of Fox Energy Company LLC	—	(391.6)	—
Acquisitions at IES	—	(15.7)	—
Grant received related to Crane Creek wind project	—	69.0	—
Other	(11.8)	(8.1)	2.2
Net cash used for investing activities	(336.5)	(1,022.7)	(602.6)
Financing Activities			
Short-term debt, net	(8.4)	(156.4)	179.1
Borrowing on term credit facility	—	200.0	—
Repayment of term credit facility	—	(200.0)	—
Issuance of long-term debt	200.0	1,174.0	428.0
Repayment of long-term debt	(175.0)	(363.5)	(305.2)
Proceeds from stock option exercises	85.8	38.7	55.8
Shares purchased for stock-based compensation	(142.9)	(2.0)	(89.9)

Payment of dividends			
Preferred stock of subsidiary	(3.1)	(3.1)	(3.1)
Common stock	(216.3)	(202.6)	(211.9)
Other	(9.3)	(22.4)	(24.7)
Net cash (used for) provided by financing activities	(269.2)	462.7	28.1
Net change in cash and cash equivalents	(4.3)	(5.1)	(0.7)
Cash and cash equivalents at beginning of year	22.3	27.4	28.1
Cash and cash equivalents at end of year	$18.0	$22.3	$27.4
Cash paid for interest	$146.8	$116.1	$109.7
Cash paid (received) for income taxes	6.3	(4.8)	(47.6)

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

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Summary of Significant Accounting Policies

(a) Nature of Operations—We are an energy holding company whose primary wholly owned subsidiaries at December 31, 2014, included MERC, MGU, NSG, PGL, WPS, IBS, ITF, and PDI. Of these subsidiaries, five are natural gas and/or electric utilities (MERC, MGU, NSG, PGL, and WPS). IBS is a centralized service company, ITF is a nonregulated compressed natural gas fueling business, and PDI is a nonregulated distributed solar energy company. In addition, we have an approximate 34% interest in ATC.

In August 2014, we sold UPPCO, and, in November 2014, we sold IES's retail energy business. See Note 4, Dispositions, for more information on these sales.

(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 statements of comprehensive income, consolidated balance sheets, consolidated statements of equity, and consolidated statements of cash flows, unless otherwise noted.

The financial statements include our accounts and the accounts of all of our majority owned subsidiaries, 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. See Note 10, Equity Method Investments, for more information.

(c) Reclassifications—The assets and liabilities associated with the sale of UPPCO and the sale of eight ITF compressed natural gas fueling stations were reclassified to held for sale on our December 31, 2013, balance sheet. The assets and liabilities related to the sale of IES's retail energy business were reclassified as assets and liabilities of discontinued operations on our December 31, 2013, balance sheet. In addition, the operations of IES's retail energy business were reclassified to discontinued operations on our income statements for the years ended December 31, 2013, and 2012. See Note 4, Dispositions, for more information on these sales.

(d) 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.

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

(f) 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 $269.4 million and $286.4 million, respectively.

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

Below is a summary of the significant mechanisms our utility subsidiaries had in place in 2014 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

- Fuel and purchased power costs were recovered from customers on a one-for-one basis by UPPCO, WPS's wholesale electric operations, and WPS's Michigan retail electric operations.
- WPS's 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. WPS monitors the deferral of these costs to ensure that it does not cause them to earn a greater return on common equity than authorized by the PSCW.
- The rates for all of our natural gas utilities included one-for-one recovery mechanisms for natural gas commodity costs.
- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup and energy conservation and management program costs.
- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.
- The rates of PGL and NSG included riders for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in customer rates.
- The rates of PGL, NSG, and MERC included decoupling mechanisms. These mechanisms differ by state and allow utilities to recover or refund differences between actual and authorized margins. See Note 25, Regulatory Environment, for more information.
- In 2014, PGL's rates included a cost recovery mechanism for upgrades to the Illinois natural gas utility infrastructure.

Revenues are also impacted by other accounting policies related to PGL's natural gas hub and our electric utilities' participation in the MISO market. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. WPS sells and purchases power in the MISO market. UPPCO also sold and purchased power in the MISO market until it was sold in August 2014. If WPS or UPPCO was a net seller in a particular hour, the net amount was reported as revenue. If WPS or UPPCO was a net purchaser in a particular hour, the net amount was recorded as utility cost of fuel, natural gas, and purchased power on the income statements.

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

We provide regulated electric and natural gas service to customers in Illinois, Michigan, Minnesota, and Wisconsin. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at PGL and NSG is mitigated by their rider for cost recovery or refund of uncollectible expense discussed above. 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.

(g) Inventories—Inventories consist of materials and supplies, natural gas in storage, liquid propane, emission allowances at WPS, and fossil fuels, including coal. Average cost is used to value materials and supplies, fossil fuels, liquid propane, emission allowances at WPS, and natural gas in storage for the utilities, excluding PGL and NSG. PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the Last-in, First-out (LIFO) cost method. Inventories stated on a LIFO basis represented approximately 37% of total inventories at December 31, 2014, and 30% of total inventories at December 31, 2013. The estimated replacement cost of natural gas in inventory at December 31, 2014, and December 31, 2013, exceeded the LIFO cost by $47.7 million and $151.7 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per dekatherm of $3.04 at December 31, 2014, and $4.77 at December 31, 2013.

(h) Risk Management Activities—As part of our regular operations, we enter into contracts, including options, swaps, futures, forwards, and other contractual commitments, to manage market risks such as changes in commodity prices and interest rates. See Note 6, Risk Management Activities, for more information. Derivative instruments are entered into in accordance with the terms of each subsidiary's risk management policies approved by their respective Boards of Directors and, if applicable, by their respective regulators.

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 energy-related derivatives at the utilities 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 on the maturities of the underlying contracts. We record unrealized gains and losses on derivative instruments that do not qualify for hedge accounting or regulatory deferral as a component of margins or operating and maintenance expense, depending on the nature of the transactions. 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.

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

(j) 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. The utilities 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
MERC [1]	2.49 %	1.88 %	3.07 %
MGU [2]	2.65 %	1.93 %	2.71 %
NSG	2.44 %	2.44 %	2.43 %
PGL	3.20 %	3.19 %	3.16 %
WPS – Electric	2.73 %	2.79 %	2.87 %
WPS – Natural gas	2.17 %	2.19 %	2.21 %

(1) The 2013 depreciation rate reflects the impact of a new depreciation study approved by the MPUC in July 2013. The rates were effective retroactive to January 2012. An approximate $2 million reduction in depreciation expense was recorded in 2013 related to the 2012 impact.

(2) The 2013 depreciation rate includes the impact of a $2.5 million reduction in depreciation expense that was recorded in the first quarter of 2013 as a result of the Michigan Court of Appeals order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010.

The majority of nonregulated plant is stated at cost, net of impairments recorded, and includes capitalized interest. The costs of renewals, betterments, and major overhauls are capitalized as additions to plant. Nonregulated plant acquired as a result of mergers and acquisitions have been recorded at fair value. The gains or losses associated with ordinary retirements are recorded in the period of retirement. Maintenance and repair costs and minor replacement costs are expensed as incurred. Depreciation is computed for the majority of the nonregulated subsidiaries' assets using the straight-line method over the assets' useful lives.

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 15 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 7, Property, Plant, and Equipment, for more information.

(k) AFUDC and Capitalized Interest—Our utilities and IBS 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.

The majority of AFUDC is recorded at WPS. Approximately 50% of WPS's retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. For 2014, WPS's average AFUDC retail rate was 8.08%, and its average AFUDC wholesale rate was 6.99%. The AFUDC calculation for the other utilities and IBS is determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities and IBS did not record significant AFUDC for 2014, 2013, or 2012.

Total AFUDC was as follows for the years ended December 31:

	2014	2013	2012
Allowance for equity funds used during construction	$12.5	$10.8	$2.9
Allowance for borrowed funds used during construction	5.2	4.1	1.0

(l) 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 9, Regulatory Assets and Liabilities, for more information.

(m) Investments in Exchange-Traded Funds—We have investments in exchange-traded funds. These investments are held in a rabbi trust to help fund our obligations under our deferred compensation plan and certain non-qualified pension plans. These investments are classified as trading securities for accounting purposes. As we do not intend to sell them in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were $1.8 million, $1.9 million, and $1.0 million for the years ended December 31, 2014, 2013, and 2012, respectively.

(n) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 11, Goodwill and Other Intangible Assets, for more information on our goodwill and other intangible assets.

The carrying amount of tangible long-lived assets held and used is considered not recoverable if the carrying amount exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying amount over its fair value.

The carrying amount of assets held for sale is not recoverable if the carrying amount exceeds the fair value less estimated costs to sell the asset. An impairment loss is recorded for the excess of the asset’s carrying amount over the fair value less estimated costs to sell.

The carrying amounts of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(o) 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. Any gains or losses resulting from the retirement of nonutility debt are recorded through current earnings.

(p) 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 15, Asset Retirement Obligations, for more information.

(q) 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 17, 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 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.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the 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.

(r) Income Taxes—We file a consolidated United States income tax return that includes domestic subsidiaries of which our ownership is 80% or more. We and our consolidated subsidiaries are parties to a federal and state tax allocation arrangement under which each entity determines its provision for income taxes on a stand-alone basis. In several states, combined or consolidated filings are required for certain subsidiaries doing business in that state.

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. Our utilities 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 on 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 16, Income Taxes, for more information regarding accounting for income taxes.

(s) 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 22, Guarantees, for more information.

(t) 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 estimated using the following approaches by plan. For plans sponsored by IBS and WPS, we use the calculated value approach. For plans sponsored by PELLC, we use the fair market value approach. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by WPS, while differences between actual investment returns and the expected return on plan assets are recognized over a five-year period for plans sponsored by IBS and PELLC. The benefit costs associated with employee benefit plans are allocated among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP.

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. Our nonregulated businesses record changes in the funded status in accumulated other comprehensive income. The utilities record changes in the funded status to regulatory asset or liability accounts, pursuant to the Regulated Operations Topic of the FASB ASC.

See Note 18, Employee Benefit Plans, for more information.

(u) Stock-Based Compensation—In May 2014, our shareholders approved the 2014 Omnibus Incentive Compensation Plan (2014 Omnibus Plan). Under the provisions of the 2014 Omnibus Plan, the number of shares of stock that may be issued in satisfaction of plan awards may not exceed 3,000,000 shares, plus any shares forfeited under prior plans. No single employee who is our chief executive officer, chief financial officer, or any one of our other three highest compensated officers (including officers of our subsidiaries) can be granted stock options for more than 1,000,000 shares or receive a payout in excess of 250,000 shares for performance stock rights during any calendar year. Additional awards will not be issued under prior plans, although the plans continue to exist for purposes of the existing outstanding stock-based compensation awards. At December 31, 2014, stock options, performance stock rights, and restricted share units were outstanding under prior plans.

Stock Options

Our 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 our stock on the date the stock option is granted.

Effective October 24, 2014, our Board of Directors accelerated the vesting of all unvested stock options held by active employees in order to help mitigate the tax impacts of Section 280G of the Internal Revenue Code on us and certain of our 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. Our expected stock price volatility is estimated using the 10-year historical volatility of our stock price.

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, our 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 and certain of our employees.

Performance stock rights are paid out in shares of our 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 our 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 our 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 our 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 our 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. Our expected stock price 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 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 our 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.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. The number of DSUs granted is calculated by dividing a set dollar amount by our closing common stock price on December 31 of the prior year. DSUs generally vest over one year. Therefore, the expense for these awards is recognized pro-rata over the year in which the grant occurs. Upon vesting, these awards are deferred into the deferred compensation plan; however, their value cannot be diversified among the various investment options. As DSUs can only be settled in our common stock, they are accounted for as equity awards.

(v) Earnings Per Share—Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for shares we are obligated to issue under the deferred compensation and restricted share unit plans. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, restricted share units, unvested director DSUs, and certain shares issuable under the deferred compensation plan. As the obligation for the shares issuable under the deferred compensation plan is accounted for as a liability, the numerator is adjusted for any changes in income or loss that would have resulted had it been accounted for as an equity instrument during the period.

(w) 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 methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

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

When possible, we base the valuations of our risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on observable inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), and price correlation (for cross commodity contracts). Transactions valued using these inputs are classified in Level 2.

Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- Financial contracts used to manage transmission congestion costs in the MISO market are valued using historical prices.
- The valuation for physical coal contracts is based on significant assumptions made to extrapolate prices from the last observable period through the end of the transaction term.
- Certain natural gas contracts are valued using internally-developed inputs due to the absence of available market data for certain locations.

We have established risk oversight committees 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 any of the supply functions within the organization. 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 instruments 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 of these items approximates fair value.

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

See Note 24, Fair Value, for more information.

(x) 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.

In April 2014, the FASB issued ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." The guidance raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. Management early adopted this guidance in the third quarter of 2014. See Note 4, Dispositions, for more information.

In January 2014, the FASB issued ASU 2014-01, "Accounting for Investments in Qualified Affordable Housing Projects." The guidance allows investors to use the proportional amortization method to account for investments in qualified affordable housing projects if certain conditions are met. Under that method, which replaces the effective yield method, an investor amortizes the cost of its investment, in proportion to the tax credits and other tax benefits it receives, to income tax expense. The guidance also requires new disclosures for all investments in these types of projects. The guidance is effective for us for the reporting period ending March 31, 2015. Although we have investments in affordable housing projects, adoption of this guidance is not expected to have a significant impact on our financial statements.

Note 2—Proposed Merger with Wisconsin Energy Corporation

In June 2014, we entered into an Agreement and Plan of Merger (Agreement) with Wisconsin Energy Corporation (Wisconsin Energy). Under this Agreement, upon the close of the transaction our shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash for each share of our common stock then owned. In addition, under the Agreement all of our unvested stock-based compensation awards will fully vest upon the close of the transaction and will be paid out in cash to award recipients. Upon closing of the transaction, our shareholders will own approximately 28% of the combined company, and Wisconsin Energy shareholders will own approximately 72%.

The combined entity will be named WEC Energy Group, Inc. and will serve more than 4.3 million total natural gas and electric customers across Wisconsin, Illinois, Michigan, and Minnesota.

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, ICC, MPSC, and MPUC, as well as other customary closing conditions. We are a party to a contested settlement agreement with the MPSC staff and all but one of the parties in the MPSC approval docket. 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 the Michigan electric distribution assets of Wisconsin Energy and WPS, 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—Acquisitions

Agreement to Purchase Alliant Energy Corporation's Natural Gas Distribution Business in Southeast Minnesota

In September 2013, MERC entered into an agreement to purchase Alliant Energy Corporation's natural gas distribution business in southeast Minnesota. This transaction was approved by the MPUC. The purchase price will be based on book value as of the closing date, which is expected to approximate $14 million. We anticipate closing on this transaction by the end of the second quarter of 2015. It will not be material to us.

Acquisition of Fox Energy Center

In March 2013, WPS acquired all of the equity interests in Fox Energy Company LLC for $391.6 million. Fox Energy Company LLC was dissolved into WPS 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 WPS 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	$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 11, Goodwill and Other Intangible Assets, for more information.

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

WPS received regulatory approval to defer incremental costs incurred in 2013 associated with the purchase of the facility. These costs are included in WPS's 2015 retail electric rate increase. See Note 25, Regulatory Environment, for more information. WPS's 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 WPS. The plant is now part of WPS's regulated fleet, used to serve its customers.

Note 4—Dispositions

Dispositions

Holding Company and Other Segment – Sale of Compressed Natural Gas (CNG) Fueling Stations

In November 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC, a joint venture between ITF and AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of AMP Trillium LLC. The fair value of the CNG fueling stations was $13.0 million. ITF received cash proceeds of $7.2 million, a $2.7 million note receivable from the buyer with a seven-year term, and a $3.1 million equity interest in the joint venture to maintain its ownership interest. In November 2014, we recorded a pre-tax gain of $1.8 million related to the sale of the CNG fueling stations and deferred a gain of $0.8 million that is being recognized over the lives of the stations sold. The pre-tax gain was reported as a component of operating and maintenance expense on the income statement.

In the third quarter of 2014, we early adopted the guidance in FASB ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." Under this guidance, the results of operations of a component of a business that is sold are only accounted for as discontinued operations if the sale represents a shift in strategy that has (or will have) a major effect on the entity's operations and financial results. The sale of the CNG stations did not represent a shift in our strategy. Therefore, the results of operations of the CNG fueling stations prior to the sale remain in continuing operations.

Net property, plant, and equipment of $10.4 million was included with the sale on November 1, 2014, which is net of accumulated depreciation of $0.7 million. Net property, plant, and equipment of $5.3 million were classified as held for sale on the balance sheet at December 31, 2013, which was net of accumulated depreciation of $0.3 million.

Electric Utility Segment – Sale of UPPCO

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP for $336.7 million. In the third quarter of 2014, we recorded a pre-tax gain of $85.4 million ($51.2 million after-tax) related to the sale of UPPCO, which was net of transaction costs of $1.1 million. Following the sale, we are providing certain administrative and operational services to UPPCO during a transition period of 18 to 30 months.

The sale of UPPCO was evaluated for accounting purposes prior to our early adoption of ASU 2014-08. UPPCO met the criteria in the accounting guidance to qualify as held for sale but did not meet the requirements to qualify as discontinued operations as WPS has significant continuing cash flows related to certain power purchase transactions with UPPCO that continued after the sale. Therefore, UPPCO's results of operations through the sale date remain in continuing operations.

The following table shows the carrying values of the major classes of assets and liabilities related to UPPCO:

(Millions)	As of the Closing Date in August 2014	Held for Sale at December 31, 2013
Current assets	$24.3	$26.5
Property, plant, and equipment, net of accumulated depreciation of $91.3 and $88.9, respectively	194.4	193.8
Other long-term assets	72.8	51.6
Total assets	$291.5	$271.9
Current liabilities	$12.7	$16.7
Long-term liabilities	28.6	32.4
Total liabilities	$41.3	$49.1

In addition to the amounts in the table above, intercompany payables of $1.6 million at December 31, 2013 related to certain power purchase transactions with WPS that continued after the sale were eliminated during consolidation. As of the closing date, these payables were included in the sale and disclosed in the table above as current liabilities.

Holding Company and Other Segment – Winnebago Energy Center

In May 2014, a fire significantly damaged the Winnebago Energy Center, a landfill-gas-to-electric facility that was owned by PDI. Due to uncertainty surrounding the amount of the insurance settlement, we were unable to determine if we would rebuild or abandon the Winnebago Energy Center in the second quarter of 2014. In the third quarter of 2014, we decided to abandon the facility and received proceeds of $6.1 million for both insurance recovery for the damage caused by the fire and from the sale of miscellaneous parts. As a result, we recorded a pre-tax gain of $5.0 million.

In the third quarter of 2014, we early adopted the guidance in FASB ASU 2014-08, as stated previously. Based on this new guidance, the Winnebago Energy Center did not qualify as discontinued operations since it did not represent a shift in our strategy. Therefore, its results of operations prior to the fire remain in continuing operations.

Discontinued Operations

See Note 5, Cash and Cash Equivalents, for cash flow information related to discontinued operations.

Holding Company and Other Segment – Potential Sale of Combined Locks Energy Center (Combined Locks)

We are currently pursuing the sale of Combined Locks, a natural gas-fired co-generation facility located in Wisconsin. Combined Locks had $0.7 million of assets that were classified as held for sale on the balance sheets at December 31, 2014, and December 31, 2013, which included inventories and property, plant, and equipment. We recorded after-tax losses of $0.5 million, $1.3 million, and $0.6 million in 2014, 2013, and 2012, respectively, in discontinued operations related to Combined Locks.

IES Segment – Sale of IES Retail Energy Business

In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC (Exelon) for $333.0 million. The purchase price is subject to adjustments for working capital. We recorded a pre-tax loss on the sale of $28.8 million ($17.3 million after tax), which included transaction costs of $4.5 million in 2014. Included in these costs is an immaterial amount related to severances. As part of the purchase agreement, we will continue to hold certain guarantees supporting the IES retail energy business for up to six months following the sale. Exelon is obligated under the purchase agreement to replace these guarantees with its own credit support for the IES retail energy business. See Note 22, Guarantees, for more information. Following the sale, we are providing certain administrative and operational services to Exelon during a transition period of up to 15 months.

The retail energy business consisted of mostly financial assets and liabilities; therefore, it did not qualify as held for sale under the applicable accounting guidance. In the third quarter of 2014, we early adopted the guidance in FASB ASU 2014-08, as stated previously. The sale of the retail energy business is a result of a previously announced shift in our strategy to focus on our regulated businesses. Therefore, its results of operations were classified as discontinued operations beginning in the fourth quarter of 2014.

The following table shows the carrying values of the major classes of assets and liabilities included in the sale:

(Millions)	As of the Closing Date in November 2014	December 31, 2013
Cash and cash equivalents	$7.6	$5.5
Accounts receivable and accrued unbilled revenues, net of reserves of $1.8 and $1.7, respectively	293.8	390.9
Inventories	52.4	34.2
Current assets from risk management activities	234.8	229.5
Prepaid taxes	—	2.5
Other current assets	75.1	41.5
Property, plant, and equipment, net of accumulated depreciation of $16.6 and $15.6, respectively	4.5	5.2
Long-term assets from risk management activities	106.9	73.4
Goodwill	—	6.7
Other long-term assets	25.5	26.0
Total assets	$800.6	$815.4
Accounts payable	$186.9	$202.9
Current liabilities from risk management activities	169.7	160.6
Accrued taxes	0.2	2.0
Other current liabilities	6.7	13.1
Long-term liabilities from risk management activities	79.5	61.9
Other long-term liabilities	0.3	7.0
Total liabilities	$443.3	$447.5

Included in the sale were commodity contracts that did not meet the GAAP definition of derivative instruments and, therefore, were not reflected on the balance sheets. In accordance with GAAP, expected gains or losses related to nonderivative commodity contracts are not recognized until the contracts are settled.

The following table shows the components of discontinued operations related to the sale of the IES retail energy business recorded on the income statements:

(Millions)	2014	2013	2012
Revenues	$2,587.1	$2,150.9	$1,201.0
Cost of sales	(2,444.7)	(1,910.7)	(1,018.9)
Operating and maintenance expense	(91.5)	(105.6)	(88.3)
Depreciation and amortization expense	(2.7)	(3.2)	(3.4)
Taxes other than income taxes	(4.9)	(3.2)	(2.4)
Goodwill impairment loss	(6.7)	—	—
Loss on sale of IES retail energy business	(28.8)	—	—
Miscellaneous income	0.6	7.9	0.3
Interest expense	(0.7)	(0.8)	(1.3)
Income before taxes	7.7	135.3	87.0
Provision for income taxes *	(7.3)	(52.8)	(31.9)

Discontinued operations, net of tax	$0.4	$82.5	$55.1

* See Note 16, Income Taxes, for more information.

The June 2014 announcement of the potential sale triggered an interim goodwill impairment test. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss in the second quarter of 2014. This goodwill impairment loss reflected the offers received for IES's retail energy business.

Holding Company and Other Segment – Sale of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse)

In March 2013, WPS Empire State, Inc. sold all of the membership interests of Beaver Falls and Syracuse, both of which owned natural gas-fired generation plants located in the state of New York. We recorded a pre-tax impairment loss of $1.1 million ($0.7 million after tax) related to Beaver Falls and Syracuse during 2012 when the assets and liabilities were classified as held for sale. This impairment loss is reflected in operating and maintenance expense in the table below. The sale agreement included a potential annual payment to us for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). In September 2014, we entered into an agreement to receive $2.0 million in settlement of this earn-out agreement, which is presented in operating and maintenance expense in the table below.

The following table shows the components of discontinued operations related to Beaver Falls and Syracuse recorded on the income statements:

(Millions)	2014	2013	2012
Revenues	$—	$1.2	$0.6
Cost of sales	—	(0.9)	(2.0)
Operating and maintenance expense	2.0	0.4 *	(3.5)
Depreciation and amortization expense	—	—	(0.6)
Taxes other than income taxes	—	(0.3)	(1.4)
Miscellaneous income	—	—	0.3
Income (loss) before taxes	2.0	0.4	(6.6)
(Provision) benefit for income taxes	(0.8)	(0.2)	2.6
Discontinued operations, net of tax	$1.2	$0.2	$(4.0)

*Includes a $1.0 million gain on sale at closing.

Holding Company and Other Segment – Uncertain Tax Positions

In 2014, we recorded a $0.7 million after-tax gain at the holding company and other segment when we remeasured an uncertain tax position included in our liability for unrecognized tax benefits due to a lapse in the statute of limitations. During 2013 and 2012, we recorded a $5.9 million after-tax gain and a $1.8 million after-tax gain, respectively, in discontinued operations at the holding company and other segment. We remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. We reduced the provision for income taxes related to these remeasurements.

Holding Company and Other Segment – Sale of WPS Westwood Generation, LLC (Westwood)

In November 2012, Sunbury Holdings, LLC, a subsidiary of IES, sold all of the membership interests of Westwood, a waste coal generation plant located in Pennsylvania. We recorded a pre-tax impairment loss of $8.4 million ($5.0 million after tax) related to Westwood during the third quarter of 2012 when the assets and liabilities were classified as held for sale. This impairment loss is reflected in operating and maintenance expense in the table below.

The following table shows the components of discontinued operations related to Westwood recorded on the income statements:

(Millions)	2012
Revenues	$9.2
Cost of sales	(4.4)
Operating and maintenance expense	(14.3) *
Depreciation and amortization expense	(1.0)
Taxes other than income taxes	(0.2)
Interest expense	(0.7)
Loss before taxes	(11.4)
Benefit for income taxes	4.5
Discontinued operations, net of tax	$(6.9)

*Includes a $0.6 million loss on sale at closing.

Note 5—Cash and Cash Equivalents

Continuing Operations

Significant noncash transactions related to continuing operations were:

(Millions)	2014	2013	2012
Construction costs funded through accounts payable	$180.5	$108.5	$92.4
Accounts receivable converted to notes receivable related to sales of ITF fueling stations constructed on behalf of others	10.9	—	—
Portion of ITF fueling station sale financed with note receivable *	2.7	—	—
Equity interest in joint venture received for a portion of the ITF fueling station sale *	3.1	—	—
Equity issued for employee stock ownership plan	1.7	14.3	—
Equity issued for stock-based compensation plans	—	16.3	—
Equity issued for reinvested dividends	—	12.0	—

* See Note 4, Dispositions, for more information.

At December 31, 2014, restricted cash of $31.3 million was recorded within other long-term assets on our balance sheet. This amount was held in the rabbi trust and was a portion of the required funding for the rabbit trust that was triggered by the announcement of the proposed merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information about the proposed merger. See Note 18, Employee Benefit Plans, for more information on the rabbi trust funding requirements.

Discontinued Operations

Following our early adoption of FASB ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity," we changed the presentation of our cash flow statement and no longer present cash flows related to discontinued operations separately. Significant noncash transactions and other information related to discontinued operations are disclosed below.

(Millions)	2014	2013	2012
Operating Activities			
Depreciation and amortization expense	$2.7	$3.3	$5.3
Net unrealized gains on energy contracts	(22.7)	(100.3)	(34.5)
Deferred income taxes and investment tax credits	36.1	56.1	(0.4)
Remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits	(0.7)	(5.9)	(1.8)
Loss on sale of IES's retail energy business *	24.3	—	—
Other	33.4	23.8	21.7
Investing Activities			
Capital expenditures	(0.8)	(2.6)	(2.0)
Contingent consideration and payables related to the acquisition of Compass Energy Services	—	7.8	—
Portion of Westwood sale financed with note receivable *	—	—	4.0

* See Note 4, Dispositions, for more information.

See Note 1(x), New Accounting Pronouncements, for more information about the adoption of FASB ASU 2014-08.

Note 6—Risk Management Activities

The following tables show our assets and liabilities from risk management activities at the utilities and IBS:

(Millions)	Balance Sheet Presentation	December 31, 2014 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Nonhedge derivatives			
Natural gas contracts	Other current	$1.8	$37.3
Natural gas contracts	Other long-term	0.5	5.3
Financial transmission rights (FTRs)	Other current	2.2	0.3
Petroleum product contracts	Other current	—	2.7
Petroleum product contracts	Other long-term	—	0.1
Coal contracts	Other current	—	2.4
Coal contracts	Other long-term	—	1.0
	Other current	4.0	42.7
	Other long-term	0.5	6.4
Total		$4.5	$49.1

(Millions)	Balance Sheet Presentation	December 31, 2013 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Nonhedge derivatives			
Natural gas contracts	Other current	$8.3	$1.0
Natural gas contracts	Other long-term	1.8	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	9.9	3.2
	Other long-term	2.0	0.9
Total		$11.9	$4.1

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	$3.2	$1.3	$1.9
Derivative assets not subject to master netting or similar arrangements	1.3		1.3
Total risk management assets	$4.5		$3.2
Derivative liabilities subject to master netting or similar arrangements	$45.7	$8.8	$36.9
	3.4		3.4

Derivative liabilities not subject to master netting or similar arrangements			
Total risk management liabilities	$49.1		$40.3

(Millions)	December 31, 2013 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	$11.7	$2.1	$9.6
Derivative assets not subject to master netting or similar arrangements	0.2		0.2
Total risk management assets	11.9		9.8
Derivative liabilities subject to master netting or similar arrangements	$1.4	$1.4	$—
Derivative liabilities not subject to master netting or similar arrangements	2.7		2.7
Total risk management liabilities	$4.1		$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	$11.6	$3.6
Other	1.1	1.1
Cash collateral received from others related to contracts under master netting or similar arrangements	—	0.7

Certain of our derivative and nonderivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a liability position at December 31, 2014, and 2013, was $31.3 million, and $0.6 million, respectively. At December 31, 2014, and 2013, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in commodity instruments (including derivatives, nonderivatives, normal purchase and normal sales contracts, and applicable payables and receivables) had been triggered at December 31, 2014, we would have been required to post collateral of $27.1 million. If all of the credit risk-related contingent features contained in commodity instruments had been triggered at December 31, 2013, we would not have been required to post collateral.

Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, coal purchase contracts, financial derivative contracts, and FTRs. The electric utility segment uses FTRs to manage electric transmission congestion costs. The natural gas and electric utility segments use financial derivative contracts to manage the risks associated with the market price volatility of natural gas supply costs. In addition, IBS enters into financial derivative contracts on behalf of the utilities to manage the cost of gasoline and diesel fuel used by utility vehicles.

The notional volumes of outstanding derivative contracts at the utilities and IBS were as follows:

	December 31, 2014			December 31, 2013		
(Millions)	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	1,860.0	—	N/A	3,124.8	29.3	N/A
FTRs (kilowatt-hours)	N/A	N/A	4,287.7	N/A	N/A	3,427.0
Petroleum products (barrels)	0.1	—	N/A	0.1	—	N/A
Coal (tons)	3.0	—	N/A	4.8	—	N/A

The table below shows the unrealized gains (losses) recorded related to derivative contracts at the utilities and IBS:

(Millions)	Financial Statement Presentation	2014	2013	2012
Natural gas	Balance Sheet — Regulatory assets (current)	$(38.0)	$13.4	$24.6
Natural gas	Balance Sheet — Regulatory assets (long-term)	(5.2)	2.3	8.3
Natural gas	Balance Sheet — Regulatory liabilities (current)	(3.9)	4.6	(7.8)

Natural gas	Balance Sheet — Regulatory liabilities (long-term)	(0.6)	0.3	0.3
Natural gas	Income Statement — Cost of sales	—	—	0.2
Natural gas	Income Statement — Operating and maintenance expense	(0.8)	0.1	—
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	—
Petroleum	Income Statement — Operating and maintenance expense	(1.7)	0.1	—
Coal	Balance Sheet — Regulatory assets (current)	(1.3)	(0.9)	(2.2)
Coal	Balance Sheet — Regulatory assets (long-term)	—	3.5	0.1
Coal	Balance Sheet — Regulatory liabilities (current)	(0.2)	(0.2)	0.3
Coal	Balance Sheet — Regulatory liabilities (long-term)	(0.1)	(2.0)	2.2

Holding Company and Other Segment

Cash Flow Hedges

In May 2010, we entered into interest rate swaps that were designated as cash flow hedges to hedge the variability in forecasted interest payments on a debt issuance. These swaps were terminated when the related debt was issued in November 2010. Amounts remaining in accumulated OCI were being reclassified to interest expense over the life of the related debt.

	Loss Reclassified from Accumulated OCI into Income (Effective Portion)			
(Millions)	Income Statement Presentation	2014	2013	2012
Settled/Realized				
Interest rate swaps	Interest expense	$(1.1)	$(1.1)	$(1.1)

Note 7—Property, Plant, and Equipment

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

(Millions)	2014	2013
Electric utility	$3,587.4	$3,289.2
Natural gas utility	5,811.8	5,428.5
Total utility property, plant, and equipment	9,399.2	8,717.7
Less: Accumulated depreciation	3,185.9	3,073.2
Net	6,213.3	5,644.5
Construction work in progress	351.8	351.5
Plant to be retired, net *	12.5	14.4
Net utility property, plant, and equipment	6,577.6	6,010.4
Nonutility plant	144.6	131.1
Less: Accumulated depreciation	81.1	80.4
Net	63.5	50.7
Construction work in progress	73.9	38.0
Net nonutility property, plant, and equipment	137.4	88.7
PDI energy assets	140.2	109.8
Other nonregulated	33.7	20.7
Total nonregulated property, plant, and equipment	173.9	130.5
Less: Accumulated depreciation	39.5	30.5
Net	134.4	100.0
Construction work in progress	10.4	7.1
Net nonregulated property, plant, and equipment	144.8	107.1
Total property, plant, and equipment	$6,859.8	$6,206.2

* In connection with the WPS Consent Decree with the EPA, WPS 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 WPS continues 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 17, Commitments and Contingencies, for more information regarding the Consent Decree.

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist. See Note 4, Dispositions, for impairment losses recorded in discontinued operations at the holding company and other segment during 2012. The impairments were recorded on property and equipment either sold during 2012 or presented on the balance sheet as assets held for sale.

Note 8—Jointly Owned Utility Facilities

WPS holds a joint ownership interest in certain electric generating facilities. WPS is entitled to its share of generating capability and output of each facility equal to its respective ownership interest. WPS also pays its ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit its maximum exposure to additional costs. WPS records its 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	%
WPS's 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	

WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. WPS has supplied its own financing for all jointly owned projects.

Note 9—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) (2)			
Environmental remediation costs (net of insurance recoveries) (3)	$635.8	$652.1	17
Unrecognized pension and other postretirement benefit costs (4)	513.1	382.6	18
Asset retirement obligations	109.4	89.0	15
Merger and acquisition-related pension and other postretirement benefit costs (5)	86.6	98.3	
Income tax related items	60.6	55.3	16
Derivatives	55.2	11.7	1(h)
Termination of a tolling agreement with Fox Energy Company LLC	44.6	50.0	3
Crane Creek production tax credits (6)	32.2	33.6	
Energy costs recoverable through rate adjustments (7)	22.2	17.0	
De Pere Energy Center (8)	21.4	23.8	
Unamortized loss on reacquired debt (9)	16.6	16.2	1(o)
Uncollectible expense (10)	13.6	4.7	
Energy efficiency programs (11)	2.8	16.8	
Pension and other postretirement costs recoverable through rate adjustments (12)	—	9.4	25
Decoupling	—	8.6	25
Other	18.4	19.7	
Total regulatory assets	$1,632.5	$1,488.8	
Balance Sheet Presentation			
Current assets	$118.9	$127.4	

Long-term assets	1,513.6	1,361.4
Total regulatory assets	$1,632.5	$1,488.8

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

(2) The following regulatory assets are not earning a return: environmental remediation costs at WPS; unrecognized pension and other postretirement benefit costs at MERC, NSG, and PGL; asset retirement obligations, derivatives, and uncollectible expense at all utilities; merger and acquisition-related pension and other postretirement benefit costs at NSG and PGL; natural gas costs recoverable through rate adjustments at MERC and WPS; unamortized loss on reacquired debt at NSG and PGL; energy efficiency programs at WPS; pension and other postretirement costs recoverable through rate adjustments at WPS; and decoupling at MGU. However, these regulatory assets are expected to be recovered from customers in future rates.

(3) As of December 31, 2014, we had not yet made cash expenditures for $579.9 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(4) 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.

(5) Composed of unrecognized benefit costs that existed prior to the PELLC merger and the MERC and MGU acquisitions. MERC and MGU are authorized recovery of this regulatory asset through 2026. PGL and NSG are authorized recovery of the pension portion of this regulatory asset through 2023, and they are authorized recovery of the other postretirement benefit portion through 2019.

(6) In 2012, WPS 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, WPS reversed previously recorded production tax credits. WPS 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. WPS recorded a regulatory asset for the deferral of previously recorded production tax credits and is authorized recovery of this net regulatory asset through 2039.

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

(8) Prior to WPS purchasing the De Pere Energy Center in 2002, WPS 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. WPS is authorized recovery of this regulatory asset through 2023.

(9) Amounts are recovered over the term of the replacement debt for NSG and PGL as authorized by the ICC.

(10) Represents amounts recoverable from customers related to uncollectible expense. We are allowed to recover or refund the difference between the rate case authorized uncollectible expense and the actual uncollectible write-offs reported to the applicable commissions each year.

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

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

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

(Millions)	2014	2013	See Note
Regulatory liabilities			
Removal costs (1)	$334.0	$318.0	
Decoupling	49.4	51.5	25
Unrecognized pension and other postretirement benefit costs (2)	45.2	30.2	18
Energy costs refundable through rate adjustments (3)	44.8	27.1	
Energy efficiency programs (4)	21.3	19.6	
Derivatives	19.8	6.6	1(h)
Uncollectible expense	15.7	10.1	25
Crane Creek depreciation deferral (5)	8.7	9.0	
Fox Energy Center (6)	4.6	5.6	3
Other	10.1	7.1	
Total regulatory liabilities	$553.6	$484.8	
Balance Sheet Presentation			
Current liabilities	$153.7	$101.1	

Long-term liabilities	399.9	383.7
Total regulatory liabilities	$553.6	$484.8

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

(4) Represents amounts refundable to customers related to programs at the utility subsidiaries designed to meet energy efficiency standards.

(5) Represents the book depreciation taken on the Crane Creek wind project prior to WPS's 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.

(6) Represents the deferral of incremental costs associated with WPS 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 10—Equity Method Investments

Investments in corporate joint ventures and other companies accounted for under the equity method at December 31, 2014, and 2013, were as follows:

(Millions)	2014	2013
ATC	$536.7	$508.4
INDU Solar Holdings, LLC	21.8	24.7
WRPC	7.7	7.0
AMP Trillium, LLC	5.5	—
Other	0.7	0.8
Equity method investments	$572.4	$540.9

ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at December 31, 2014. ATC is a for-profit, transmission-only company regulated by FERC.

The following table shows changes to our investment in ATC during the years ended December 31:

(Millions)	2014	2013	2012
Balance at the beginning of period	$508.4	$476.6	$439.4
Add: Earnings from equity method investment	85.7	89.1	85.3
Add: Capital contributions	17.0	13.7	20.4
Less: Dividends received	74.4	71.0	68.5
Balance at the end of period	$536.7	$508.4	$476.6

ATC is currently named in a complaint filed with the FERC requesting a reduction in the base return on equity (ROE) used by MISO transmission owners to 9.15%. ATC's current authorized ROE is 12.2%. 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, based on rulings in a similar complaint. As a result, our equity earnings and corresponding equity method investment in ATC reflected an estimated $6.6 million reduction during 2014.

The electric utilities provide construction and other services to ATC and receive network transmission services from ATC. The related party transactions recorded by the electric utilities during the years ended December 31 were as follows:

(Millions)	2014	2013	2012
Total charges to ATC for services and construction	$9.9	$11.3	$12.5
Total costs for network transmission services provided by ATC	103.8	104.9	100.3

INDU Solar Holdings, LLC

Integrys Solar, LLC, a subsidiary of PDI, owns 50% of INDU Solar Holdings, LLC. INDU Solar Holdings, LLC owns solar energy projects in California, Pennsylvania, New Jersey, Arizona, and Massachusetts that deliver electricity and related products to commercial, government, and utility customers under long-term power purchase agreements.

The following table shows changes to our investment in INDU Solar Holdings, LLC during the years ended December 31:

(Millions)	2014	2013	2012
Balance at the beginning of period	$24.7	$27.5	$28.4
Add: Earnings from equity method investment	1.8	1.3	1.1

Add: Capital contributions	—	—	7.0
Less: Return of capital to partners	4.7	4.1	9.0
Balance at the end of period	$21.8	$24.7	$27.5

WRPC

WPS owns 50% of the stock of WRPC, which owns two hydroelectric plants and an oil-fired combustion turbine. Half of the energy output of the hydroelectric plants is sold to WPS, and half is sold to Wisconsin Power and Light. The electric power from the combustion turbine is also sold in equal parts to WPS and Wisconsin Power and Light.

The following table shows changes to our investment in WRPC during the years ended December 31:

(Millions)	2014	2013	2012
Balance at the beginning of period	$7.0	$7.3	$7.7
Add: Earnings from equity method investment	0.8	1.0	0.8
Add: Capital contributions	0.5	—	—
Less: Dividends received	0.6	1.3	1.2
Balance at the end of period	$7.7	$7.0	$7.3

WPS provides services to WRPC, purchases energy from WRPC, and receives net proceeds from sales of energy into the MISO market from WRPC. The related party transactions recorded by WPS during the years ended December 31 were as follows:

(Millions)	2014	2013	2012
Charges to WRPC for operations	$1.4	$0.9	$0.8
Purchases of energy from WRPC	3.7	3.7	5.0
Net proceeds from WRPC sales of energy to MISO	—	—	2.9

AMP Trillium, LLC

AMP Trillium, LLC is a joint venture between ITF and AMP Americas, LLC. ITF owns 30% and AMP Americas, LLC owns 70% of this joint venture. AMP Trillium, LLC owns and operates compressed natural gas (CNG) fueling stations. In April 2014, ITF and AMP Americas, LLC restructured this joint venture. Prior to the restructuring, we consolidated AMP Trillium, LLC. However, due to the restructuring, we started accounting for AMP Trillium, LLC as an equity method investment in April 2014. See Note 27, Variable Interest Entities, for more information.

The following table shows changes to our investment in AMP Trillium, LLC during the year ended December 31:

(Millions)	2014
Balance at the beginning of period	$—
Add: Capital contributions	5.5
Balance at the end of period	$5.5

ITF sells CNG fueling stations to AMP Trillium, LLC and provides financial support to AMP Trillium, LLC through loans. At December 31, 2014, ITF had $13.8 million of notes receivable due from AMP Trillium, LLC. During 2014, ITF recorded $3.1 million of net proceeds from the sale of CNG fueling stations to AMP Trillium, LLC.

Financial Data

Combined financial data of our significant equity method investments, ATC, INDU Solar Holdings, LLC, WRPC, and AMP Trillium, LLC, are included in the tables below:

(Millions)	2014	2013	2012
Income statement data			
Revenues	$655.6	$642.0	$618.3
Operating expenses	323.5	306.2	292.1
Other expense	88.4	83.7	85.1
Net income	$243.7	$252.1	$241.1
Earnings from equity method investments	$88.3	$91.4	$87.2

(Millions)	December 31, 2014	December 31, 2013

Balance sheet data		
Current assets	$80.7	$90.2
Noncurrent assets	3,835.9	3,587.2
Total assets	$3,916.6	$3,677.4
Current liabilities	$324.0	$383.6
Long-term debt	1,721.6	1,559.1
Other noncurrent liabilities	173.2	134.4
Shareholders’ equity	1,697.8	1,600.3
Total liabilities and shareholders’ equity	$3,916.6	$3,677.4

Note 11—Goodwill and Other Intangible Assets

The following table shows changes to our goodwill balances by segment during the years ended December 31, 2014, and 2013:

	Natural Gas Utility		Holding Company and Other		Total	
(Millions)	2014	2013	2014	2013	2014	2013
Balance as of January 1						
Gross goodwill	$933.5	$933.5	$19.6	$15.8	$953.1	$949.3
Accumulated impairment losses	(297.7)	(297.7)	—	—	(297.7)	(297.7)
Net goodwill as of January 1	635.8	635.8	19.6	15.8	655.4	651.6
Adjustment to ITF intellectual property *	—	—	—	3.8	—	3.8
Balance as of December 31						
Gross goodwill	933.5	933.5	19.6	19.6	953.1	953.1
Accumulated impairment losses	(297.7)	(297.7)	—	—	(297.7)	(297.7)
Net goodwill as of December 31	$635.8	$635.8	$19.6	$19.6	$655.4	$655.4

* An immaterial adjustment was made to the gross goodwill balance at ITF in the second quarter of 2013 due to a correction to the life of certain intangible assets.

In the second quarter of 2014, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of April 1, 2014. No impairments resulted from these tests.

The identifiable intangible assets other than goodwill listed below are part of 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 [1]	$15.6	$ (4.3)	$11.3	$15.6	$ (1.8)	$13.8
Customer-owned equipment modifications [2]	4.0	(1.2)	2.8	4.0	(0.9)	3.1
Intellectual property [3]	3.4	(0.8)	2.6	3.4	(0.5)	2.9
Nonregulated easements [4]	3.9	(1.4)	2.5	3.7	(1.1)	2.6
Compressed natural gas fueling contract assets [5]	5.6	(3.6)	2.0	5.6	(2.7)	2.9
Customer-related [6]	1.9	(0.3)	1.6	1.9	(0.1)	1.8
Other	0.5	(0.3)	0.2	0.5	(0.3)	0.2
Total	$34.9	$ (11.9)	$23.0	$34.7	$ (7.4)	$27.3
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name [7]	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name [7]	1.5	—	1.5	1.5	—	1.5
Total intangible assets	$45.1	$ (11.9)	$33.2	$44.9	$ (7.4)	$37.5

(1)

Represents 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. In October 2014, WPS 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, WPS shortened the amortization period of one of its service agreements. The remaining weighted-average amortization period for these intangible assets at December 31, 2014, was approximately four years. Since WPS has approval from the PSCW to recover the value of its 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.

(2) Relates to modifications made by PDI and ITF to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at December 31, 2014, of approximately nine years.

(3) Represents the fair value of intellectual property at ITF related to a system for more efficiently compressing natural gas to allow for faster fueling. An immaterial adjustment was made to the intangible assets balance in the second quarter of 2013 as a result of a correction to the life of the intangible assets. The remaining amortization period at December 31, 2014, was approximately eight years.

(4) Relates to easements supporting a pipeline at PDI. The easements are amortized on a straight-line basis, with a remaining amortization period at December 31, 2014, of approximately nine years.

(5) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at December 31, 2014, was approximately six years.

(6) Represents customer relationship assets associated with ITF's compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at December 31, 2014, was approximately 12 years.

(7) Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) are wholly owned subsidiaries of ITF.

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

(Millions)	2014	2013	2012
Amortization recorded in cost of sales	$1.2	$1.6	$1.3
Amortization recorded in depreciation and amortization expense	3.0	2.5	1.0
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 cost of sales	$1.1	$0.9	$0.9	$0.8	$0.6
Amortization to be recorded in depreciation and amortization expense	3.0	2.9	2.4	1.9	1.9
Amortization to be recorded in regulatory assets	1.0	1.0	0.5	—	—

Note 12—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 $14.7 million, $11.2 million, and $11.0 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	$4.7
2016	5.0
2017	5.8
2018	5.6
2019	4.7
Later years	47.6
Total	$73.4

Note 13—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)	$317.6	$326.0		$482.4	
Average interest rate on amount outstanding at December 31	0.36%	0.22	%	0.40	%
Average amount outstanding during the year (2)	$283.0	$378.4		$326.3	
Short-term notes payable (3)					
Average amount outstanding during the year (2)	$—	$130.4	(4)	$—	

(1) Maturity dates ranged from January 2, 2015, through January 16, 2015.

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

(3) We did not have short-term notes payable outstanding at December 31, 2014, 2013, and 2012.

(4) Average amount outstanding of a $200.0 million loan used for the purchase of Fox Energy Company LLC. This loan was repaid in November 2013. See Note 3, Acquisitions, 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 (Integrys Energy Group) [1]	05/17/2014	$—	$275.0
Revolving credit facility (Integrys Energy Group) [1]	05/17/2016	—	200.0
Revolving credit facility (Integrys Energy Group) [2]	06/13/2017	285.0	635.0
Revolving credit facility (Integrys Energy Group)	05/08/2019	465.0	—
Revolving credit facility (WPS) [1]	05/17/2014	—	135.0
Revolving credit facility (WPS) [3]	05/07/2015	135.0	—
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0
Total short-term credit capacity		$1,250.0	$1,610.0
Less:			
Letters of credit issued inside credit facilities		$3.4	$52.4
Commercial paper outstanding		317.6	326.0
Available capacity under existing agreements		$929.0	$1,231.6

(1) These credit facilities were terminated and replaced with new credit facilities in May 2014.

(2) This credit facility was reduced by $350 million during the fourth quarter of 2014 due to the sale of IES.

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

Our revolving credit agreements and those of certain of our subsidiaries contain 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 14—Long-Term Debt

(Millions)				December 31 2014	2013
WPS First Mortgage Bonds [1]					
	Series	Year Due			
	7.125 %	2023		$0.1	$0.1
WPS Senior Notes [1]					
	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
PGL First and Refunding Mortgage Bonds [2]					
	Series	Year Due			
	QQ, 4.875%	2038	Mandatory interest reset date on November 1, 2018	—	75.0
	RR, 4.30%	2035	Mandatory interest reset date on June 1, 2016	50.0	50.0
	TT, 8.00%	2018		5.0	5.0
	UU, 4.63%	2019		75.0	75.0
	VV, 3.90%	2030		50.0	50.0
	WW, 2.625%	2033	Mandatory interest reset date on August 1, 2015	50.0	50.0
	XX, 2.21%	2016		50.0	50.0
	YY, 3.98%	2042		100.0	100.0
	ZZ, 4.00%	2033		50.0	50.0
	AAA, 3.96%	2043		220.0	220.0
	BBB, 4.21%	2044		200.0	—
NSG First Mortgage Bonds [3]					
	Series	Year Due			
	P, 3.43%	2027		28.0	28.0
	Q, 3.96%	2043		54.0	54.0

Integrys Energy Group Unsecured Senior Notes [4]					
	Series	Year Due			
	7.27 %	2014		—	100.0
	8.00 %	2016		55.0	55.0
	4.17 %	2020		250.0	250.0
Integrys Energy Group Unsecured Junior Subordinated Notes [5]					
	Series	Year Due			
	6.11 %	2066	Interest to become variable on December 1, 2016	269.8	269.8
	6.00 %	2073	Mandatory interest reset date on August 1, 2023	400.0	400.0
Total				3,081.9	3,056.9
Unamortized discount on debt				(0.6)	(0.7)
Total debt				3,081.3	3,056.2
Less current portion				125.0	100.0
Total long-term debt				$2,956.3	$2,956.2

(1) WPS's First Mortgage Bonds and Senior Notes are subject to the terms and conditions of WPS's First Mortgage Indenture dated January 1, 1941, as supplemented. Under the terms of the Indenture, substantially all property owned by WPS is pledged as collateral for these outstanding debt securities. All of these debt securities require semi-annual payments of interest. WPS Senior Notes become noncollateralized if WPS retires all of its outstanding First Mortgage Bonds and no new mortgage indenture is put in place.

In December 2015, our 6.375% Senior Notes will mature. As a result, the $125 million balance of these notes was included in the current portion of long-term debt on our balance sheet at December 31, 2014.

(2) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued equal principal amounts of certain collateralized First Mortgage Bonds.

In November 2014, PGL issued $200.0 million of 4.21% Series BBB Bonds. These bonds are due in November 2044. A portion of the proceeds was used to redeem PGL's $75.0 million 4.875% Series QQ Bonds.

(3) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

(4) In June 2014, our $100.0 million of 7.27% Unsecured Senior Notes matured, and the outstanding principal balance was repaid.

(5) The 6.11% Junior Subordinated Notes are considered hybrid instruments with a combination of debt and equity characteristics. Under a replacement capital covenant with the holders of our 4.17% Unsecured Senior Notes due November 1, 2020, prior to December 1, 2036, any amounts redeemed or repurchased in excess of 10% of the principal amount outstanding must first be replaced with a specified amount of proceeds from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the 6.11% Junior Subordinated Notes.

The 6.00% Junior Subordinated Notes are considered hybrid instruments with a combination of debt and equity characteristics. There is no replacement capital covenant associated with these securities.

Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. In addition, certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

A schedule of all principal debt payment amounts related to bond maturities is as follows:

(Millions)	Payments
2015	$125.0
2016	105.0
2017	125.0
2018	5.0
2019	75.0
Later years	2,646.9
Total	$3,081.9

Note 15—Asset Retirement Obligations

The utility segments have asset retirement obligations primarily related to removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation facilities, office buildings, and service centers; dismantling wind generation projects; disposal of PCB-contaminated transformers; closure of fly-ash landfills at certain generation facilities; and removal of above ground storage tanks. The utilities 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. PDI has asset retirement obligations related to the removal of solar equipment components.

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

(Millions)	Utilities	PDI	Total
Asset retirement obligations at December 31, 2011	$395.8	$0.5	$396.3
Accretion	20.3	0.1	20.4
Additions and revisions to estimated cash flows	(2.3)	1.6	(0.7)
Settlements	(5.4)	—	(5.4)
Asset retirement obligations at December 31, 2012	408.4	2.2	410.6
Accretion	20.8	0.1	20.9
Additions and revisions to estimated cash flows	70.1 *	0.5	70.6
Settlements	(11.1)	—	(11.1)
Asset retirement obligations at December 31, 2013	488.2	2.8	491.0
Accretion	24.5	0.1	24.6
Additions and revisions to estimated cash flows	(18.3) *	0.7	(17.6)
Settlements	(17.8)	—	(17.8)
Asset retirement obligations at December 31, 2014	$476.6	$3.6	$480.2

* Revisions were made to estimated cash flows related to asset retirement obligations primarily due to changes in the weighted average cost to retire natural gas distribution pipe at PGL.

Note 16—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
Deferred income tax assets		
Tax credit carryforwards	$116.7	$113.5
Price risk management	—	13.0
Other	77.4	98.5
Total deferred income tax assets	$194.1	$225.0
Valuation allowance	(3.6)	(8.2)
Net deferred income tax assets	$190.5	$216.8
Deferred income tax liabilities		
Plant-related	$1,584.1	$1,373.8
Regulatory deferrals	55.6	78.8
Employee benefits	45.4	79.6
Other	23.0	43.5
Total deferred income tax liabilities	$1,708.1	$1,575.7
Total net deferred income tax liabilities	$1,517.6	$1,358.9
Balance sheet presentation		
Current deferred income tax assets	$52.4	$31.4
Long-term deferred income tax liabilities	1,570.0	1,390.3
Net deferred income tax liabilities	$1,517.6	$1,358.9

Deferred tax credit carryforwards at December 31, 2014, included $73.9 million of alternative minimum tax credits, which can be carried forward indefinitely. Other deferred tax credit carryforwards included $32.5 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 2034. Deferred tax credit carryforwards also included $6.2 million of foreign tax credits, which have a carryback period of one year and a carryforward period of 10 years. The majority of the foreign tax credit carryforwards will expire in 2019. We also had $4.2 million of deferred state tax credit carryforwards, which have a carryforward period of five years. The majority of the state tax credit carryforwards will expire in 2018.

At December 31, 2014, we had deferred income tax assets of $27.0 million reflecting federal operating loss carryforwards, which have a carryback period of two years and a carryforward period of 20 years. We also had deferred income tax assets of $19.2 million reflecting net state operating loss carryforwards. The majority of the state operating loss carryforwards relate to Wisconsin and have a carryforward period of 20 years. Any deferred tax assets that are not used to offset future taxable income will expire between 2020 and 2033 as follows:

(Millions)	
2020 through 2025	$7.6
2026 through 2031	2.9
2032 through 2033	35.7

Valuation allowances are established for certain state operating losses based on our projected ability to realize these benefits by offsetting future taxable income. Realization is dependent on generating sufficient taxable income prior to expiration. As of December 31, 2014, the entire valuation allowance was related to noncurrent deferred income tax assets. The valuation allowance was reduced by $4.6 million in 2014 due to a foreign tax deduction.

Our utilities record certain adjustments related to deferred income taxes to regulatory assets and liabilities. As the related temporary differences reverse, the utilities 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 asset for these net recoveries and other regulatory tax effects totaled $58.8 million and $51.6 million at December 31, 2014, and 2013, respectively. See Note 9, 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 Taxes

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

(Millions)	2014	2013	2012
Current provision			
Federal	$19.9	$1.6	$(17.4)
State	25.2	4.7	(1.7)
Total current provision	45.1	6.3	(19.1)
Deferred provision			
Federal	123.0	134.1	119.8
State	18.7	9.9	17.9
Total deferred provision	141.7	144.0	137.7
Investment tax credits			
Deferral	13.2	12.3	17.8
Amortization	(5.2)	(4.0)	(12.6)
Penalties	—	(0.1)	(0.3)
Unrecognized tax benefits	0.7	0.4	(2.9)
Interest	(2.1)	(0.9)	(2.7)
Total provision for income taxes related to continuing operations	193.4	158.0	117.9
Total provision for income taxes related to discontinued operations	7.2	45.9	22.6
Total	$200.6	$203.9	$140.5

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 from continuing operations before taxes.

	2014		2013		2012	
(Millions, except for percentages)	Rate	Amount	Rate	Amount	Rate	Amount
Statutory federal income tax	35.0 %	$165.0	35.0 %	$148.9	35.0 %	$124.9
State income taxes, net	7.5 *	35.5 *	3.7	15.9	4.9	17.6
Benefits and compensation	(0.9)	(4.3)	(1.0)	(4.1)	(2.6)	(9.3)
Other differences, net	(0.6)	(2.8)	(0.6)	(2.7)	(4.3)	(15.3)
Effective income tax	41.0 %	$193.4	37.1 %	$158.0	33.0 %	$117.9

* Includes the impact of a $13.0 million expense caused by the remeasurement of deferred taxes related to the sale of IES's retail energy business.

With the exception of 2014, income taxes on discontinued operations are recorded at rates that are not materially different from the applicable statutory rates. In 2014, the rate varied from the applicable statutory rates primarily because of the impairment of nondeductible goodwill related to IES's retail energy business.

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	$3.6	$11.3	$22.4

Increase related to tax positions taken in prior years	—	2.2	0.9
Decrease related to tax positions taken in prior years	(0.1)	(8.7)	(6.7)
Increase related to tax positions taken in current year	0.5	0.3	0.6
Decrease related to settlements	—	(1.5)	(5.7)
Decrease related to lapse of statutes	(0.7)	—	(0.2)
Balance at December 31	$3.3	$3.6	$11.3

We had accrued interest of $0.3 million and accrued penalties of $0.2 million related to unrecognized tax benefits at December 31, 2014. We had accrued interest of $0.8 million and accrued penalties of $0.4 million related to unrecognized tax benefits at December 31, 2013.

Our effective tax rate could be affected by recognition of $2.2 million of unrecognized tax benefits related to continuing operations in periods after December 31, 2014.

Our subsidiaries file income tax returns in the United States federal jurisdiction, in various state and local jurisdictions, and in Canada.

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, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. With a few exceptions, 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 state or local tax authorities for the 2008 through 2013 tax years in our major state operating jurisdictions as follows:

State	Year
Illinois	2008
Michigan	2008
Minnesota	2011
Wisconsin	2010

During 2014, the Michigan taxing authority continued its examination of the 2008 through 2011 tax years and the Illinois taxing authority initiated its examination of the 2008 through 2010 tax years.

As of December 31, 2014, we were subject to examination by foreign income tax authorities for the 2009 through 2013 tax years. With a few exceptions, we are no longer subject to foreign income tax examinations by tax authorities for years prior to 2009.

In the next 12 months, it is reasonably possible that we and our subsidiaries will settle open examinations in multiple taxing jurisdictions related to tax years prior to 2012, resulting in a decrease in unrecognized tax benefits of up to $1.3 million.

Note 17—Commitments and Contingencies

(a) Unconditional Purchase Obligations

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2014, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Date Contracts Extend Through	Total Amounts Committed	2015	2016	2017	2018	2019	Later Years
Natural gas utility supply and transportation	2028	$722.6	$196.6	$170.4	$132.9	$78.2	$50.9	$93.6
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	—
Total		$1,722.2	$374.7	$245.1	$218.8	$166.0	$119.0	$598.6

(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 WPS 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. WPS 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. WPS announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant associated with 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 7, Property, Plant, and Equipment, for more information.

WPS received approval from the PSCW in its 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 proposed by WPS have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

In May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of December 31, 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 WPS. The NOV alleges violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, 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 WPS's portion totaling $1.3 million, and
- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, 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 WPS 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, WPS challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also challenged various aspects of the permit. The WDNR granted all parties' requests for contested case proceedings. The Petitions for Judicial Review, by all parties, have been stayed pending the resolution of the contested cases. In February 2014, WPS 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 WPS challenged this issue as well. At WPS's 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 WPS 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) to WPS alleging that WPS failed to comply with reporting requirements related to challenged matters in the 2013 Weston Title V permit. The ALJ recently denied WPS's 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.

WPS was in compliance with the State of Wisconsin's mercury rule at the end of 2014. In addition, WPS is making progress toward compliance with the MATS rule in 2015. WPS estimated capital costs of approximately $9 million for its 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 WPS, 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 to lift the stay on CSAPR and changed the compliance deadlines by three years, so that Phase 1 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, 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, WPS will comply with the rule on the timeline required under the regulation. WPS will evaluate the impact of compliance by conducting the studies required by the rule at its facilities. WPS anticipates 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 WPS's 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

Our natural gas utilities, their predecessors, and certain former affiliates 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, our natural gas utilities are required to undertake remedial action with respect to some of these materials. The natural gas utilities 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.

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 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 $579.7 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 $54.6 million. Our balance sheet also includes a regulatory asset of $634.3 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.

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 for MGU, NSG, PGL, and WPS. 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 various regulatory commissions with respect to the prudence of costs actually incurred, could materially affect recovery of such costs through rates.

Note 18—Employee Benefit Plans

Defined Benefit Plans

We and our subsidiaries maintain a noncontributory, qualified pension plan covering the majority of our employees, as well as several unfunded nonqualified retirement plans. In addition, we and our subsidiaries offer multiple other postretirement benefit plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

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.

In August 2014, we sold UPPCO. The pension and other postretirement plan assets and obligations related to UPPCO employees and retirees transferred with the sale and are disclosed in the table below. The impact of this transfer has been reflected in the measurement of the gain on sale of UPPCO. See Note 4, Dispositions, for more information.

The following tables provide a reconciliation of the changes in our 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	$1,641.7	$1,784.9	$576.3	$621.0
Service cost	24.8	30.2	21.0	24.9
Interest cost	76.2	71.2	23.5	24.8
Plan amendments	—	—	(90.4)	0.2
Divestitures - UPPCO	(100.4)	—	(22.3)	—
Actuarial loss (gain), net	166.1	(153.1)	33.1	(73.4)
Participant contributions	—	—	10.0	10.6
Benefit payments	(102.7)	(91.5)	(33.3)	(34.0)
Federal subsidy on benefits paid	—	—	2.1	2.2
Obligation at December 31	$1,705.7	$1,641.7	$520.0	$576.3
Change in fair value of plan assets				
Fair value of plan assets at January 1	$1,527.7	$1,348.1	$470.1	$424.4
Actual return on plan assets	94.6	205.4	18.2	57.8
Employer contributions	98.8	65.7	10.0	11.3
Participant contributions	—	—	10.0	10.6
Divestitures - UPPCO	(122.8)	—	(27.3)	—
Benefit payments	(102.7)	(91.5)	(33.3)	(34.0)
Fair value of plan assets at December 31	$1,495.6	$1,527.7	$447.7	$470.1
Funded Status at December 31	$(210.1)	$(114.0)	$(72.3)	$(106.2)

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	$—	$—	$1.5	$—

Current liabilities	9.1	8.9	0.2	0.2
Liabilities held for sale	—	6.9	—	3.4
Long-term liabilities	201.0	98.2	73.6	102.6
Total net liabilities	$(210.1)	$(114.0)	$(72.3)	$(106.2)

The accumulated benefit obligation for the defined benefit pension plans was $1,531.1 million and $1,489.1 million at December 31, 2014, and 2013, respectively.

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

(Millions)	2014	2013
Projected benefit obligation	$64.1	$65.4
Accumulated benefit obligation	61.2	63.0

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
Accumulated other comprehensive loss (pre-tax) [(1)]				
Net actuarial loss	$40.2	$33.3	$0.2	$0.7
Prior service credits	—	—	(0.1)	(0.2)
Total	$40.2	$33.3	$0.1	$0.5
Net regulatory assets [(2)]				
Net actuarial loss	$501.0	$356.2	$50.4	$6.2
Prior service costs (credits)	1.8	2.4	(85.3)	(12.4)
Total	$502.8	$358.6	$(34.9)	$(6.2)

(1) Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

(2) Amounts related to the utilities are recorded as net regulatory assets or liabilities.

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

(Millions)	Pension Benefits	Other Benefits
Net actuarial loss	$43.2	$4.4
Prior service costs (credits)	0.2	(10.3)
Total 2015 – estimated amortization	$43.4	$(5.9)

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	$24.8	$30.2	$46.0	$21.0	$24.9	$20.8
Interest cost	76.2	71.2	78.0	23.5	24.8	28.5
Expected return on plan assets	(112.4)	(105.5)	(107.9)	(33.0)	(30.6)	(28.2)
Loss on plan settlement	0.9	—	—	—	—	—
Amortization of transition obligation	—	—	—	—	—	0.3
Amortization of prior service cost (credit)	0.6	4.0	5.0	(9.4)	(2.5)	(3.4)
Amortization of net actuarial loss	33.3	56.7	34.0	3.2	8.4	6.6
Net periodic benefit cost	$23.4	$56.6	$55.1	$5.3	$25.0	$24.6

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%	4.00%	4.83%
Rate of compensation increase	4.23%	4.24%	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 the 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	4.23%	4.25%	4.25%

	Other Benefits		
	2014	2013	2012
Discount rate	4.65%	3.96%	4.94%
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%	5.50%
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 our 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	$6.1	$(5.0)
Effect on the health care component of the accumulated postretirement benefit obligation	58.7	(55.1)

Pension and Other Postretirement Benefit Plan Assets

Our 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 our 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 established the Employee Benefits Administrator Committee (composed of members of 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(w), 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	$—	$42.3	$—	$42.3	$8.5	$2.6	$—	$11.1
Equity securities:								
United States equity	91.0	336.2	—	427.2	20.6	122.8	—	143.4
International equity	92.4	383.9	—	476.3	18.7	117.8	—	136.5
Fixed income securities:								
United States government	70.3	21.6	—	91.9	111.1	—	—	111.1
Foreign government	—	20.6	—	20.6	—	—	—	—
Corporate debt	—	425.7	—	425.7	—	—	—	—
Other	—	53.5	—	53.5	1.0	—	—	1.0
	253.7	1,283.8	—	1,537.5	159.9	243.2	—	403.1
401(h) other benefit plan assets invested as pension assets (1)	(7.4)	(37.2)	—	(44.6)	7.4	37.2	—	44.6
Total (2)	$246.3	$1,246.6	$—	$1,492.9	$167.3	$280.4	$—	$447.7

(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.

	December 31, 2013							
	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	$2.0	$36.6	$—	$38.6	$—	$4.0	$—	$4.0
Equity securities:								
United States equity	100.4	445.1	—	545.5	21.4	132.2	—	153.6
International equity	114.1	429.0	—	543.1	19.5	125.5	—	145.0
Fixed income securities:								
United States government	—	93.6	—	93.6	121.2	0.7	—	121.9
Foreign government	—	16.9	2.4	19.3	—	—	—	—
Corporate debt	—	250.0	1.3	251.3	—	—	—	—
Asset-backed securities	—	61.8	—	61.8	—	—	—	—
Other	—	17.4	—	17.4	1.0	—	—	1.0
	216.5	1,350.4	3.7	1,570.6	163.1	262.4	—	425.5
401(h) other benefit plan assets invested as	(6.1)	(37.9)	(0.1)	(44.1)	6.1	37.9	0.1	44.1

pension assets [1]								
Total [2]	$210.4	$1,312.5	$3.6	$1,526.5	$169.2	$300.3	$0.1	$469.6

(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.

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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	$2.4	$1.3	$3.7
Sales	(2.4)	(1.3)	(3.7)
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	Asset-Backed Securities	Total
Beginning balance at January 1, 2013	$4.1	$1.0	$0.1	$5.2
Net realized and unrealized losses	(0.3)	(0.4)	—	(0.7)
Purchases	0.6	—	—	0.6
Sales	(2.0)	(0.4)	—	(2.4)
Transfers into Level 3	—	1.4	—	1.4
Transfers out of Level 3	—	(0.3)	(0.1)	(0.4)
Ending balance at December 31, 2013	$2.4	$1.3	$—	$3.7
Net unrealized losses related to assets still held at the end of the period	$(0.2)	$(0.3)	$—	$(0.5)

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 $9.1 million to the pension plans and $8.7 million to other postretirement benefit plans in 2015, dependent upon various factors affecting us, including our liquidity position and possible tax law changes. In 2015, contributions of $7.0 million will be funded through a transfer of assets from the rabbi trust for certain nonqualified pension plans. See the discussion below in regard to the triggering of the full funding of the rabbi trust.

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	$124.6	$23.7
2016	122.3	26.0
2017	127.6	28.4
2018	126.0	30.6
2019	136.5	33.3
2020 through 2024	644.4	195.8

Rabbi Trust Funding

The Agreement and Plan of Merger entered into with Wisconsin Energy Corporation in June 2014 triggered the potential change in control provisions in the rabbi trust agreement. These provisions required the full funding of the present value of each participant's total benefit under the deferred compensation program and certain nonqualified pension plans. As a result, $65.0 million was moved to the rabbi trust in June 2014, $64.8 million, consisting of cash and exchange-traded funds, was moved to the rabbi trust in July 2014, and an additional $2.4 million was moved to the rabbi trust in December 2014. These amounts were included in other long-term assets on the balance sheet as of December 31, 2014. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information.

Defined Contribution Benefit Plans

We maintain 401(k) Savings Plans for substantially all of our full-time employees. A percentage of employee contributions are matched through an employee stock ownership plan (ESOP) contribution or cash 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. The ESOP held 3.9 million shares of our common stock (market value of $303.5 million) at December 31, 2014. 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. Total costs incurred under all of these plans were $35.0 million in 2014, $36.4 million in 2013, and $19.1 million in 2012.

We maintain deferred compensation plans that enable certain key employees and nonemployee directors to defer payment of a portion of their compensation or fees on a pre-tax basis. Nonemployee directors can defer up to 100% of their director fees. Compensation is generally deferred in the form of cash and is indexed to certain investment options or our common stock. The deemed dividends paid on the common stock are automatically reinvested.

The deferred compensation arrangements for which distributions are made solely in our 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 $24.3 million at December 31, 2014, and $24.8 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 $64.4 million at December 31, 2014, and $53.4 million at December 31, 2013. The costs incurred under this arrangement were $9.5 million in 2014, $6.5 million in 2013, and $3.1 million in 2012.

Historically, the deferred compensation programs were partially funded through shares of our common stock that are held in a rabbi trust. The common stock held in the rabbi trust is classified as a reduction of equity in a manner similar to accounting for treasury stock. The total cost of our common stock held in the rabbi trust was $20.9 million at December 31, 2014, and $23.0 million at December 31, 2013.

Note 19—Preferred Stock of Subsidiary

Our subsidiary, WPS, has 1,000,000 authorized shares of preferred stock with no mandatory redemption and a $100 par value. Outstanding shares owned by third parties were as follows at December 31:

(Millions, except share amounts)	2014		2013	
Series	Shares Outstanding	Carrying Value	Shares Outstanding	Carrying Value
5.00%	130,692	$13.1	130,692	$13.1
5.04%	29,898	3.0	29,898	3.0
5.08%	49,905	5.0	49,905	5.0
6.76%	150,000	15.0	150,000	15.0
6.88%	150,000	15.0	150,000	15.0
Total	510,495	$51.1	510,495	$51.1

All shares of WPS 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 WPS. Each series of outstanding preferred stock is redeemable in whole or in part at WPS's option at any time on 30 days' notice at the respective redemption prices. WPS may not redeem less than all, nor purchase any, of its preferred stock during the existence of any dividend default.

In the event of WPS's 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 20—Common Equity

We had the following changes to issued common stock:

Balance at December 31, 2011	78,287,906

Balance at December 31, 2012 *	78,287,906
Shares issued	
Stock-based compensation	972,718
Stock Investment Plan	298,532
Employee Stock Ownership Plan	248,724
Rabbi trust shares	111,296
Balance at December 31, 2013	79,919,176
Shares issued	
Stock Investment Plan	12,151
Employee Stock Ownership Plan	31,764
Balance at December 31, 2014	79,963,091

* We did not issue equity during 2012.

The following table provides a summary of common stock activity to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans:

Period	Method of meeting requirements
Beginning 02/05/2014	Purchasing shares on the open market
02/05/2013 – 02/04/2014	Issued new shares
01/01/2012 – 02/04/2013	Purchased shares on the open market

Under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we cannot issue shares of our common stock.

The following table reconciles common shares issued and outstanding:

	2014		2013	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,963,091		79,919,176	
Less:				
Deferred compensation rabbi trust	428,920	$48.73	473,796	$48.50
Total common shares outstanding	79,534,171		79,445,380	

* Based on our stock price on the day the shares entered the deferred compensation rabbi trust. Shares paid out of the trust are valued at the average cost of shares in the trust.

Earnings Per Share

The following table reconciles our computation of basic and diluted earnings per share:

(Millions, except per share amounts)	2014	2013	2012
Numerator:			
Net income from continuing operations	$278.1	$267.5	$238.9
Discontinued operations, net of tax	1.8	87.3	45.4
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.1	0.2
Net income attributed to common shareholders — basic	$276.9	$351.8	$281.4
Effect of dilutive securities			
Deferred compensation	—	(0.1)	—
Net income attributed to common shareholders — diluted	$276.9	$351.7	$281.4
Denominator:			
Average shares of common stock — basic	80.2	79.5	78.6
Effect of dilutive securities			
Stock-based compensation	0.5	0.4	0.5
Deferred compensation	—	0.2	0.2
Average shares of common stock — diluted	80.7	80.1	79.3
Earnings per common share			
Basic	$3.45	$4.43	$3.58
Diluted	3.43	4.39	3.55

The calculation of diluted earnings per share excluded the following weighted-average outstanding securities that had an anti-dilutive effect:

(Millions)	2014	2013	2012

Stock-based compensation	0.2	0.3	0.7
Deferred compensation	0.3	0.1	—

Dividend Restrictions

Our ability as a holding company to pay dividends is largely dependent upon the availability of funds from our subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our utility subsidiaries to transfer funds to us in the form of dividends. Our utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly.

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

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

PGL and WPS have short-term debt obligations containing 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 their outstanding debt obligations.

As of December 31, 2014, total restricted net assets of consolidated subsidiaries were $1,953.0 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $157.5 million at December 31, 2014.

We also have short-term and long-term debt obligations that contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of outstanding debt obligations. At December 31, 2014, these covenants did not restrict our retained earnings or the payment of any dividends.

We have the option to defer interest payments on our outstanding Junior Subordinated Notes, from time to time, for one or more periods of up to ten consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment on, any of our capital stock.

Under the merger agreement with Wisconsin Energy, we may not declare or pay any dividends or distributions on our common stock other than the regular quarterly dividend of $0.68 per share.

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

Capital Transactions with Subsidiaries

During 2014, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
IBS	$ —	$ —	$ 25.0
ITF [1]	—	—	50.3
MERC	—	27.0	20.0
MGU	—	13.0	7.0
PGL[1]	—	—	65.0
UPPCO	—	12.5	94.4
WPS	111.8	—	55.0
WPS Investments, LLC [2]	74.3	—	17.0
Total	$ 186.1	$ 52.5	$ 333.7

(1)

ITF and PGL are direct wholly owned subsidiaries of PELLC. As a result, they make distributions to PELLC, and receive equity contributions from PELLC. Subject to applicable law, PELLC does not have any dividend restrictions or limitations on distributions to us.

(2) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us and WPS. In August 2014, UPPCO's ownership interest in WPS Investments, LLC was transferred to us as a result of the sale of UPPCO. At December 31, 2014, the ownership interest held by us and WPS was 89.02% and 10.98%, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2014, all equity contributions to WPS Investments, LLC were made solely by us.

Note 21—Accumulated Other Comprehensive Loss

The following table shows the changes, net of tax, to our accumulated other comprehensive loss:

(Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at December 31, 2012	$ (5.2)	$ (35.7)	$ (40.9)
Other comprehensive income before reclassifications	0.7	13.2	13.9
Amounts reclassified out of accumulated other comprehensive loss	1.4	2.4	3.8
Net 2013 other comprehensive income	2.1	15.6	17.7
Balance at December 31, 2013	(3.1)	(20.1)	(23.2)
Other comprehensive loss before reclassifications	—	(6.0)	(6.0)
Amounts reclassified out of accumulated other comprehensive loss	(0.1)	1.7	1.6
Net 2014 other comprehensive loss	(0.1)	(4.3)	(4.4)
Balance at December 31, 2014	$ (3.2)	$ (24.4)	$ (27.6)

The following table shows the reclassifications out of accumulated other comprehensive loss during the years ended December 31:

	Amount Reclassified		
(Millions)	2014	2013	Affected Line Item in the Statements of Income
Losses (gains) on cash flow hedges			
Utility commodity derivative contracts	$—	$0.2	Operating and maintenance expense [1] [2]
Nonregulated commodity derivative contracts	—	3.7	Discontinued operations [2]
Interest rate hedges	1.1	1.1	Interest expense
	1.1	5.0	Total before tax
	1.2	3.6	Tax expense
	(0.1)	1.4	Net of tax
Defined benefit plans			
Amortization of prior service costs (credits)	(0.2)	4.3	[3]
Amortization of net actuarial losses (gains)	2.7	(0.2)	[3]
	2.5	4.1	Total before tax
	0.8	1.7	Tax expense
	1.7	2.4	Net of tax
Total reclassifications	$1.6	$3.8	

(1) This item relates to changes in the price of natural gas used to support utility operations.

(2) We no longer designate commodity contracts as cash flow hedges.

(3) These items are included in the computation of net periodic benefit cost. See Note 18, Employee Benefit Plans, for more information.

Note 22—Guarantees

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at December 31, 2014	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$189.3	$105.1	$—	$84.2
Standby letters of credit (2)	1.2	1.1	0.1	—
Surety bonds (3)	25.1	25.0	0.1	—
Other guarantees (4)	73.5	—	—	73.5
Guarantees temporarily retained related to the sale of IES's retail energy business (5)	279.5	$248.4	$1.8	$29.3
Total guarantees	$568.6	$379.6	$2.0	$187.0

(1) Consists of (a) $5.0 million to support the business operations of IBS, and (b) $0.4 million, $127.4 million, $44.7 million, and $11.8 million related to natural gas supply at ITF, MERC, MGU, and PDI, respectively. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $1.2 million issued to support ITF, MERC, MGU, NSG, PDI, PGL, and WPS. These amounts are not reflected on our balance sheets.

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

(4) Consists of (a) $46.1 million to support PDI's future payment obligations related to its distributed solar generation projects; (b) $10.0 million related to the sale agreement for IES’s Texas retail marketing business. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the tax law; (c) $11.2 million related to the performance of an operating and maintenance agreement by ITF; and (d) $6.2 million related to other indemnifications primarily for workers compensation coverage. The amounts discussed in items (a), (c), and (d) above are not reflected on our balance sheets.

(5) These guarantees are retained temporarily due to the sale of IES's retail energy business to Exelon Generation Company, LLC (Exelon). For up to six months after the sale, we will continue to provide these guarantees until either Exelon can replace them or until they expire. Exelon is contractually bound to reimburse us for any payments we make under the outstanding guarantees. These guarantees consist of (a) $267.4 million of guarantees supporting commodity transactions; (b) $6.9 million of standby letters of credit; (c) $3.4 million of surety bonds; and (d) $1.8 million related to the sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC. Following the guidance of the Guarantees Topic of the FASB ASC, an insignificant liability related to these guarantees was recorded at fair value on our balance sheet. Our exposure under these guarantees related to open transactions at December 31, 2014, was $168.9 million.

Note 23—Stock-Based Compensation

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

(Millions)	2014	2013	2012
Stock options	$2.7	$1.8	$2.0
Performance stock rights	16.8	2.7	5.0
Restricted share units	9.9	8.6	8.1
Nonemployee director deferred stock units	0.8	0.9	1.0
Total stock-based compensation expense	$30.2	$14.0	$16.1
Deferred income tax benefit	$12.1	$5.6	$6.4

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 stock 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	1,550,374	$ 50.93		
Granted	264,332	55.23		
Exercised	(1,676,831)	51.33		
Forfeited	(3,858)	55.23		
Outstanding at December 31, 2014	134,017	$ 54.31	6.6	$3.2
Exercisable at December 31, 2014	59,714	$ 55.21	5.6	$1.4

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 our 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, 2013, and 2012, was $32.0 million, $9.0 million, and $11.0 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $12.8 million, $3.6 million, and $4.4 million during 2014, 2013, and 2012, respectively.

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	85,749	$ 46.62
Granted	21,146	44.28
Award modifications	64,612	85.09
Distributed [(1)]	(74,345)	77.67
Adjustment for estimated payout and shares not distributed [(1)]	(28,591)	52.67
Forfeited	(308)	44.28
Outstanding at December 31, 2014	68,263	$ 58.54

(1) No shares of 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, our 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	198,904
Granted	84,529
Award modifications	(64,612)
Distributed *	(10,760)
Adjustment for estimated payout and shares not distributed *	(36,519)
Forfeited	(1,234)
Outstanding at December 31, 2014	170,308

*

No shares of 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, our 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 $108.51 per performance stock right.

As of December 31, 2014, $4.2 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 $6.4 million, $8.8 million, and $4.7 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during 2014, 2013, and 2012, was $2.6 million, $3.6 million, and $1.9 million, respectively.

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	511,301	$ 52.24
Granted	214,953	55.23
Dividend equivalents	21,422	54.47
Vested and released	(208,964)	49.76
Forfeited	(111,407)	54.62
Outstanding at December 31, 2014	427,305	$ 54.45

As of December 31, 2014, $7.3 million of unrecognized 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 $11.4 million, $11.7 million, and $10.7 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 $4.6 million, $4.7 million, and $4.3 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during 2014, 2013, and 2012, was $55.23, $55.93, and $53.24 per unit, respectively.

Note 24—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
Assets				
Risk Management Assets				
Natural gas contracts	$—	$2.3	$—	$2.3
Financial transmission rights (FTRs)	—	—	2.2	2.2
Coal contracts	—	—	—	—
Total Risk Management Assets	$—	$2.3	$2.2	$4.5
Investment in Exchange-Traded Funds	$102.4	$—	$—	$102.4
Liabilities				
Risk Management Liabilities				
Natural gas contracts	$4.8	$31.2	$6.6	$42.6
FTRs	—	—	0.3	0.3
Petroleum product contracts	2.8	—	—	2.8
Coal contracts	—	1.2	2.2	3.4
Total Risk Management Liabilities	$7.6	$32.4	$9.1	$49.1

	December 31, 2013			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Natural gas contracts	$2.4	$7.7	$—	$10.1
FTRs	—	—	1.5	1.5
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	0.2	0.2
Total Risk Management Assets	$2.5	$7.7	$1.7	$11.9
Investment in Exchange-Traded Funds	$15.9	$—	$—	$15.9
Liabilities				
Risk Management Liabilities				
Natural gas contracts	$0.5	$0.6	$—	$1.1
FTRs	—	—	0.3	0.3
Coal contracts	—	—	2.7	2.7
Total Risk Management Liabilities	$0.5	$0.6	$3.0	$4.1

The risk management assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO market. See Note 6, Risk Management Activities, for more information on derivative instruments.

Transfers between levels of the fair value hierarchy were not significant during 2014. 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 transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Natural gas contracts	$ —	$ 6.6	Income-based	Option volatilities [(1)]	50.5% – 67.2%
FTRs	2.2	0.3	Market-based	Forward market prices ($/megawatt-month) [(2)]	$188.16
Coal contracts	—	2.2	Market-based	Forward market prices ($/ton) [(3)]	$10.89 – $13.60

(1) Represents the range of volatilities used in the valuation of options. Volatilities are derived from an internal model based on volatility curves from third parties.

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

(3) Represents third-party forward market pricing.

Significant changes in option volatilities, 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:

(Millions)	2014 Natural Gas Contracts	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$—	$1.2	$ (2.5)	$(1.3)
Net realized and unrealized gains included in earnings	—	0.2	—	0.2
Net unrealized (losses) gains recorded as regulatory assets or liabilities	(6.6)	0.4	(1.6)	(7.8)
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 the period	$(6.6)	$1.9	$ (2.2)	$(6.9)

	2013		
(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$1.1	$ (6.5)	$(5.4)
Net realized and unrealized 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 the period	$1.2	$ (2.5)	$(1.3)

	2012		
(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$1.2	$ (6.9)	$(5.7)
Net realized and unrealized 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 the period	$1.1	$ (6.5)	$(5.4)

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through cost of sales on the 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	$3,081.3	$3,271.4	$3,056.2	$3,031.6
Preferred stock of subsidiary	51.1	51.8	51.1	61.2

Note 25—Regulatory Environment

Wisconsin

2015 Rates

In December 2014, the PSCW issued a final written order for WPS, effective January 1, 2015. It authorized a net retail electric rate increase of $24.6 million and a net retail natural gas rate decrease of $15.4 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.28% in WPS's regulatory capital structure. The PSCW approved a change in rate design for WPS, 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. WPS 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 17, 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 WPS 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 for WPS, 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 WPS's 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

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and Weston sites. See Note 17, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its decoupling mechanism, beginning January 1, 2014.

2013 Rates

In December 2012, the PSCW issued a final written order for WPS, 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 WPS's 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, WPS was 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 WPS 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 WPS Rate Case

In October 2014, WPS filed an application with the MPSC to increase retail electric rates $5.7 million, with interim rates expected to be effective in April 2015. WPS's request reflected a 10.60% return on common equity and a target common equity ratio of 50.48% in WPS's 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.

2014 MGU Rates

In November 2013, the MPSC issued a final written order for MGU, effective January 1, 2014. The order authorized a retail natural gas rate increase of $4.5 million. The rates reflect a 10.25% return on common equity and a common equity ratio of 48.62% in MGU's regulatory capital structure. Additionally, the order required MGU to terminate its decoupling mechanism after December 31, 2013, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2015. The new decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. The rate order also terminated MGU's uncollectible expense true-up mechanism after December 31, 2013.

MGU Depreciation Case

In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's 2010 disallowance of $2.5 million associated with the early retirement of certain MGU assets. As a result, a $2.5 million reduction to depreciation expense was recorded in the first quarter of 2013. In June 2013, the MPSC issued an order related to MGU's most recent depreciation case. This order also approved a settlement agreement reflecting recovery of these previously disallowed costs.

2014 UPPCO Rates

In December 2013, the MPSC issued a final written order for UPPCO, effective January 1, 2014. The order authorized a retail electric rate increase of $5.8 million. The rates reflected a 10.15% return on common equity and a common equity ratio of 56.74% in UPPCO's regulatory capital structure. The order required UPPCO to terminate its decoupling mechanism after December 31, 2013. In addition, the order required UPPCO to achieve certain minimum line clearance performance metrics for recovery of costs related to clearing trees and other natural obstructions away from power lines.

Illinois

2015 Rates

In January 2015, the ICC issued a final written order for PGL and NSG, effective January 28, 2015. The order authorized a retail natural gas rate increase of $74.8 million for PGL and $3.7 million for NSG. In February 2015, the ICC filed an amendatory order that revised the increases to $71.1 million for PGL and $3.5 million for NSG, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates for PGL reflected a 9.05% return on common equity and a common equity ratio of 50.33% in PGL's regulatory capital structure. The rates for NSG reflected a 9.05% return on common equity and a common equity ratio of 50.48% in NSG's regulatory capital structure. The rate orders allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, PGL plans to recover a return on certain investments and depreciation expense through the Qualifying Infrastructure Plant rider discussed below, and accordingly, such costs are not subject to PGL's rate order. In February 2015, the Attorney General and certain intervenors filed requests for rehearing on certain issues, which the ICC will rule on in March 2015.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057 (formerly Senate Bill 2266), The Natural Gas Consumer, Safety & Reliability Act, became law. The Act gave PGL a cost recovery mechanism for prudently incurred costs to upgrade Illinois natural gas infrastructure that are collected through a surcharge on customer bills. This Act eliminated a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014 and became effective on January 1, 2014.

2013 Rates

In June 2013, the ICC issued a final written order for PGL and NSG, effective June 27, 2013. The order authorized a retail natural gas rate increase of $57.2 million for PGL and $6.6 million for NSG. The rates for PGL reflected a 9.28% return on common equity and a common equity ratio of 50.43% in PGL's regulatory capital structure. The rates for NSG reflected a 9.28% return on common equity and a common equity ratio of 50.32% in NSG's regulatory capital structure. The rate order also allowed PGL and NSG to continue the use of their decoupling mechanisms, as affirmed by the Illinois Supreme Court. In addition, the ICC is required to conduct an investigation to monitor the costs and progress of the AMRP.

In August 2013, the ICC granted certain rehearing requests on tax-related issues filed by PGL, NSG, and other intervenors. PGL and NSG asked for a correction of the revenue requirement for deferred tax assets related to tax net operating losses (NOLs) incurred in 2012 and 2013. In the ICC’s order, these deferred tax assets were included in rate base, but computational errors were made. Other intervenors requested the exclusion from rate base of the deferred tax asset related to the 2012 tax NOL. The tax NOLs in question resulted from PGL and NSG claiming accelerated depreciation deductions in 2012 and 2013. In December 2013, the ICC evaluated and approved a correction of the computational errors and rejected the intervenors' proposed exclusion of the 2012 tax NOL. Customer rates were increased by $2.6 million for PGL and $0.1 million for NSG for the impact of this correction, effective January 1, 2014. In January 2014, the Illinois Attorney General and Citizens Utility Board each filed an appeal with the Illinois Appellate Court (Court). In January 2015, the Citizens Utility Board filed to withdraw its appeal, and the Illinois Attorney General requested an extension of the briefing schedule.

2012 Decoupling

The ICC issued a final written order, effective January 21, 2012, which approved a permanent decoupling mechanism for PGL and NSG. The Illinois Attorney General and Citizens Utility Board appealed to the Court the ICC's authority to approve PGL's and NSG's decoupling mechanisms and filed a motion to stay the implementation of the permanent decoupling mechanisms or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General's motion to make revenues collected under the permanent decoupling mechanisms subject to refund. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 were uncertain, and PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Court issued an opinion that affirmed the ICC's order approving the permanent decoupling mechanisms. As a result, the reserves recorded in 2012 were reversed in the first quarter of 2013. PGL's and NSG's permanent decoupling mechanism was in place for 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. In January 2015, the Illinois Supreme Court affirmed the ICC's authority to approve the permanent decoupling mechanism. As a result, decoupling amounts recorded in 2014 will be refunded to customers in 2015 as planned, and decoupling amounts in the future will continue to be accrued.

Minnesota

2014 Rates

In October 2014, the MPUC issued a final written order, which is expected to become effective in the first half of 2015. The order authorized a retail natural gas rate increase of $7.6 million. The rates reflected a 9.35% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure. The order allows for a deferral of customer billing system costs, for which the recovery will be requested in a future rate case. A decoupling mechanism with a 10% cap will remain in effect for MERC's residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, as of December 31, 2014, $3.1 million is estimated to be refunded to customers during 2015.

2011 Rates Finalized in 2013

In July 2012, the MPUC approved a final written order, effective January 1, 2013. The order authorized a retail natural gas rate increase of $11.0 million. The rates reflected a 9.70% return on common equity and a common equity ratio of 50.48% in MERC's regulatory capital structure. In addition, the order set recovery of MERC's 2011 test-year pension expense at 2010 levels. The MPUC also approved a decoupling mechanism for MERC that covers residential and small commercial and industrial customers on a three-year trial basis, effective January 1, 2013. The decoupling mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels. It includes an annual 10% cap based on distribution revenues approved in the rate case. Amounts recoverable from or refundable to customers are subject to this cap.

Note 26—Miscellaneous Income

Total miscellaneous income was as follows at December 31:

(Millions)	2014	2013	2012
Equity portion of AFUDC	$12.5	$10.8	$2.9
Federal excise tax credit	4.4	4.1	—
Gain on sale of land at the holding company	3.5	—	—
Key executive life insurance income for retired employees	2.9	2.2	2.6
Gains on exchange-traded funds	2.9	2.2	1.3
Other	4.8	2.6	2.2
Total miscellaneous income	$31.0	$21.9	$9.0

Note 27—Variable Interest Entities

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. This joint venture was established to own and operate compressed natural gas (CNG) fueling stations. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. At December 31, 2013, ITF was the primary beneficiary of this variable interest entity, and, as a result, we consolidated the assets, liabilities, and statements of income of the joint venture. However, in April 2014, ITF and AMP Americas LLC restructured this joint venture. Due to the restructuring, our influence over the activities that most significantly impact the variable interest entity's economic performance decreased. We determined that ITF is no longer the primary beneficiary of this variable interest entity and that we are no longer required to consolidate the joint venture. Therefore, we started accounting for this variable interest entity as an equity method investment in April 2014. At December 31, 2014, and December 31, 2013, our variable interests in the joint venture included an equity investment and receivables. See Note 10, Equity Method Investments, for more information. Our maximum exposure to loss as a result of this joint venture was not significant. In November 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC. See Note 4, Dispositions, for more information.

In 2013, ITF formed EVO Trillium LLC as a joint venture with Environmental Alternative Fuels LLC. ITF owns 15% and Environmental Alternative Fuels LLC owns 85% of the joint venture. This joint venture was established to own and operate CNG fueling stations. We determined that this joint venture is a variable interest entity but that consolidation is not required since we are not its primary beneficiary, as we do not have the power to direct its activities. We instead account for this variable interest entity as an equity method investment. At December 31, 2014, and December 31, 2013, the assets and liabilities on our balance sheets related to our involvement with this variable interest entity consisted of insignificant receivables and payables. Our maximum exposure to loss as a result of involvement with this variable interest entity was also not significant.

Note 28—Segments of Business

At December 31, 2014, we had four segments related to our continuing operations and one segment related to the discontinued operations of IES's retail energy business. Our reportable segments are described below.

- The natural gas utility segment includes the natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the electric utility operations of UPPCO and WPS. In August 2014, we sold UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 4, Dispositions, for more information on the sale of UPPCO.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- The IES segment includes the nonregulated energy operations of IES's retail energy business. Since we sold IES's retail energy business in November 2014, this segment only includes discontinued operations. See Note 4, Dispositions, for more information on the sale of IES's retail energy business. The remaining energy asset business, PDI, was reclassified to the holding company and other segment.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company, ITF, PDI, and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS.

All of our operations and assets are located within the United States. The tables below present information related to our reportable segments:

2014 (Millions)	Regulated Operations				Nonutility and Nonregulated Operations			
	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$2,748.0	$1,286.3	$ —	$4,034.3	$—	$109.9	$ —	$4,144.2
Intersegment revenues	12.4	0.1	—	12.5	—	1.4	(13.9)	—
Depreciation and amortization expense	149.0	103.0	—	252.0	—	36.0	(0.5)	287.5
Merger transaction costs	—	—	—	—	—	10.4	—	10.4
Gain on sale of UPPCO, net of transaction costs	—	(85.4)	—	(85.4)	—	—	—	(85.4)
Gain on abandonment of PDI's Winnebago Energy Center	—	—	—	—	—	(5.0)	—	(5.0)
Earnings from equity method investments	—	—	85.7	85.7	—	2.6	—	88.3
Miscellaneous income	1.9	11.1	—	13.0	—	29.8	(11.8)	31.0
Interest expense	54.4	47.4	—	101.8	—	64.8	(11.8)	154.8
Provision (benefit) for income taxes	65.6	103.3	34.4	203.3	—	(9.9)	—	193.4
Net income (loss) from continuing operations	100.7	166.3	51.3	318.3	—	(40.2)	—	278.1
Discontinued operations	—	—	—	—	0.4	1.4	—	1.8
Preferred stock dividends of subsidiary	(0.5)	(2.6)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	100.2	163.7	51.3	315.2	0.4	(38.7)	—	276.9
Total assets	6,292.5	3,506.9	536.7	10,336.1	—	1,638.1	(692.2)	11,282.0
Cash expenditures for long-lived assets	456.5	286.6	—	743.1	0.9	121.0	—	865.0

2013 (Millions)	Regulated Operations				Nonutility and Nonregulated Operations			
	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								

External revenues	$2,094.1	$1,332.0	$ —	$ 3,426.1	$—	$59.4	$ —	$ 3,485.5
Intersegment revenues	10.9	0.1	—	11.0	—	1.4	(12.4)	—
Depreciation and amortization expense	136.0	98.6	—	234.6	—	29.3	(0.5)	263.4
Earnings from equity method investments	—	—	89.1	89.1	—	2.4	—	91.5
Miscellaneous income	1.2	9.8	—	11.0	—	23.3	(12.4)	21.9
Interest expense	50.2	36.4	—	86.6	—	53.2	(12.4)	127.4
Provision (benefit) for income taxes	78.9	67.3	35.2	181.4	—	(23.4)	—	158.0
Net income (loss) from continuing operations	124.0	113.4	53.9	291.3	—	(23.8)	—	267.5
Discontinued operations	—	—	—	—	82.5	4.8	—	87.3
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	123.4	110.9	53.9	288.2	82.5	(18.9)	—	351.8
Total assets	5,672.0	3,514.4	508.5	9,694.9	815.4	1,519.7	(786.5)	11,243.5
Cash expenditures for long-lived assets	370.0	615.0	—	985.0	2.6	73.2	—	1,060.8

2012 (Millions)	Regulated Operations				Nonutility and Nonregulated Operations			
	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$ 1,662.7	$ 1,297.4	$ —	$ 2,960.1	$—	$ 52.8	$ —	$ 3,012.9
Intersegment revenues	9.3	—	—	9.3	—	1.9	(11.2)	—
Depreciation and amortization expense	131.8	89.0	—	220.8	—	27.0	(0.5)	247.3
Earnings from equity method investments	—	—	85.3	85.3	—	1.9	—	87.2
Miscellaneous income	0.6	2.6	—	3.2	—	19.9	(14.1)	9.0
Interest expense	47.3	35.9	—	83.2	—	49.8	(14.1)	118.9
Provision (benefit) for income taxes	61.4	49.4	32.9	143.7	—	(25.8)	—	117.9
Net income (loss) from continuing operations	94.0	110.4	52.4	256.8	—	(17.9)	—	238.9
Discontinued operations	—	—	—	—	55.1	(9.7)	—	45.4
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.2	—	0.2
Net income (loss) attributed to common shareholders	93.4	107.9	52.4	253.7	55.1	(27.4)	—	281.4
Total assets	5,446.2	3,041.3	476.6	8,964.1	493.7	1,523.3	(653.7)	10,327.4
Cash expenditures for long-lived assets	375.1	163.9	—	539.0	2.0	53.4	—	594.4

Note 29—Quarterly Financial Information (Unaudited)

In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC. See Note 4, Dispositions, for more information. Due to the sale, certain previously reported amounts have been retrospectively adjusted as IES's retail energy business has been reclassified to discontinued operations for all periods presented.

Amounts reflecting IES's retail energy business in discontinued operations (Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2014					
Operating revenues	$1,638.0	$836.8	$657.1	$1,012.3	$4,144.2
Operating income	232.3	23.2	134.6	116.9	507.0
Net income from continuing operations	140.2	8.8	75.3	53.8	278.1
Net income	153.1	8.0	84.0	34.8	279.9
Net income attributed to common shareholders	152.4	7.2	83.3	34.0	276.9
Earnings per common share (basic) *					
Net income from continuing operations	$1.74	$0.10	$0.93	$0.66	$3.43
Discontinued operations, net of tax	0.16	(0.01)	0.11	(0.24)	0.02
Earnings per common share (basic)	1.90	0.09	1.04	0.42	3.45
Earnings per common share (diluted) *					
Net income from continuing operations	1.73	0.10	0.91	0.66	3.41
Discontinued operations, net of tax	0.16	(0.01)	0.11	(0.24)	0.02
Earnings per common share (diluted)	1.89	0.09	1.02	0.42	3.43
2013					
Operating revenues	$1,136.4	$708.1	$622.2	$1,018.8	$3,485.5
Operating income	211.8	56.1	41.5	130.1	439.5
Net income from continuing operations	129.6	36.8	26.9	74.2	267.5
Net income (loss)	188.3	(4.7)	38.8	132.4	354.8
Net income (loss) attributed to common shareholders	187.5	(5.4)	38.1	131.6	351.8
Earnings (loss) per common share (basic) *					
Net income from continuing operations	$1.64	$0.45	$0.33	$0.91	$3.33
Discontinued operations, net of tax	0.74	(0.52)	0.15	0.73	1.10
Earnings (loss) per common share (basic)	2.38	(0.07)	0.48	1.64	4.43
Earnings (loss) per common share (diluted) *					
Net income from continuing operations	1.63	0.45	0.32	0.91	3.30
Discontinued operations, net of tax	0.74	(0.52)	0.15	0.72	1.09
Earnings (loss) per common share (diluted)	2.37	(0.07)	0.47	1.63	4.39

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

Previously reported amounts reflecting IES's retail energy business in continuing operations

(Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2014					
Operating revenues	$2,924.9	$1,432.6	$1,187.9	N/A	N/A
Operating income	253.2	26.1	146.9	N/A	N/A
Net income from continuing operations	153.2	8.1	82.9	N/A	N/A
Net income	153.1	8.0	84.0	N/A	N/A
Net income attributed to common shareholders	152.4	7.2	83.3	N/A	N/A
Earnings per common share (basic) *					
Net income from continuing operations	$1.90	$0.09	$1.03	N/A	N/A
Discontinued operations, net of tax	—	—	0.01	N/A	N/A
Earnings per common share (basic)	1.90	0.09	1.04	N/A	N/A
Earnings per common share (diluted) *					
Net income from continuing operations	1.89	0.09	1.01	N/A	N/A
Discontinued operations, net of tax	—	—	0.01	N/A	N/A
Earnings per common share (diluted)	1.89	0.09	1.02	N/A	N/A
2013					
Operating revenues	$1,678.2	$1,116.0	$1,129.7	$1,710.7	$5,634.6
Operating income (loss)	293.1	(6.9)	55.3	226.2	567.7
Net income (loss) from continuing operations	182.2	(3.9)	39.4	132.3	350.0
Net income (loss)	188.3	(4.7)	38.8	132.4	354.8
Net income (loss) attributed to common shareholders	187.5	(5.4)	38.1	131.6	351.8
Earnings (loss) per common share (basic) *					
Net income (loss) from continuing operations	$2.30	$(0.06)	$0.49	$1.64	$4.37
Discontinued operations, net of tax	0.08	(0.01)	(0.01)	—	0.06
Earnings (loss) per common share (basic)	2.38	(0.07)	0.48	1.64	4.43
Earnings (loss) per common share (diluted) *					
Net income (loss) from continuing operations	2.29	(0.06)	0.48	1.63	4.33
Discontinued operations, net of tax	0.08	(0.01)	(0.01)	—	0.06
Earnings (loss) per common share (diluted)	2.37	(0.07)	0.47	1.63	4.39

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

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

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

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

We have audited the internal control over financial reporting of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2014 of the Company and our report dated March 2, 2015 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP

March 2, 2015

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

None.

ITEM 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.

Reports of Independent Registered Public Accounting Firm

For our Report of Independent Registered Public Accounting Firm, see Section B of Item 8.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors and Executive Officers

The table below sets forth the following information regarding our directors, as of December 31, 2014: name, age, business background, years of service, and directorship/trusteeships currently held, or held within the last five years, in other publicly-held companies, including registered investment companies. 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 set forth in the information below, including, as applicable, past service with our company, evidences his or her ability to effectively serve as a director of Integrys Energy Group. Further, each director's background has provided the director with business acumen and a thoughtful approach to addressing issues that confront businesses. This combination of business background, skills and attributes led to the conclusion that each of the directors is qualified to serve as a director of Integrys Energy Group.

Name	Age	Director's Qualifications	Years
William J. Brodsky [(1)]	70	Director Integrys Energy Group, Inc. Executive Chairman Chairman and Chief Executive Officer CBOE Holdings, Inc. Executive Chairman Chairman and Chief Executive Officer Chicago Board Options Exchange Chief Executive Officer Chicago Mercantile Exchange	1997 – present * 2013 – 2014 2010 – 2013 2013 – present 1997 – 2013 1985 – 1997
Albert J. Budney, Jr.	67	Director Integrys Energy Group, Inc. President and Director Niagara Mohawk Holdings, Inc. (Holding company for electric and natural gas operations) President and Director Niagara Mohawk Power Corporation (Regulated electric and natural gas utility) Managing Vice President, Power Services Group UtiliCorp United, Inc. (Holding company for electric and gas operations) President Missouri Public Service Company (Regulated electric and natural gas utility)	2002 – present 1999 – 2002 1995 – 1999 1994 – 1995 1993 – 1994
Ellen Carnahan [(2)]	59	Director Integrys Energy Group, Inc. Principal	2003 – present 2008 – present

Machrie Enterprises LLC (Private equity and venture capital fund advisory services)	
Managing Director William Blair Capital Management LLC (Venture capital fund management)	1988 – 2009
Managing Director Seyen Capital Management LLC (Venture capital fund management)	2006 – 2008

* Years of service includes years of service as a director of Peoples Energy Corporation prior to the merger with Integrys Energy Group, Inc., in 2007.

(1) Mr. Brodsky currently serves as a director of the following publicly held company: CBOE Holdings, Inc.

(2) Ms. Carnahan also currently serves as a trustee for the following registered investment fund: The JNL Funds.

Name	Age	Director’s Qualifications	Years
Michelle L. Collins (3)	54	Director Integrys Energy Group, Inc. President Cambium LLC (Business and financial advisory firm) Managing Director and Co-Founder Svoboda Capital Partners, LLC (Private equity firm) Principal, Corporate Finance Associate, Corporate Finance William Blair & Company, LLC (Investment banking firm)	2011 – present 2007 – present 1998 – 2006 1992 – 1997 1986 – 1991
Kathryn M. Hasselblad-Pascale	66	Director Integrys Energy Group, Inc. Managing Partner Hasselblad Machine Company, LLP (Manufacturer of automatic screw machine products)	1987 – present 1997 – present
John W. Higgins	68	Director Integrys Energy Group, Inc. Chairman and Chief Executive Officer Higgins Development Partners, LLC (Real estate development services)	2003 – present * 1980 – present
Paul W. Jones (4)	66	Director Integrys Energy Group, Inc. Executive Chairman Chairman and Chief Executive Officer President and Chief Operating Officer A.O. Smith Corporation (Manufacturer of water heating and water treatment products) Chairman and Chief Executive Officer U.S. Can Corporation (Manufacturer of container products) Chief Executive Officer Greenfield Industries, Inc. (Manufacturer of cutting tools and material removal products)	2011 – present 2013 – 2014 2005 – 2012 2004 – 2005 1998 – 2002 1989 – 1998
Holly Keller Koeppel (5)	56	Director Integrys Energy Group, Inc. Managing Director Citi Infrastructure Investors (Investment fund)	2012 – present 2010 – present

Executive Vice President and Chief Financial Officer	2006 – 2009
Executive Vice President of Utilities – East	2004 – 2006
Executive Vice President, Commercial Operations	2003 – 2004
Executive Vice President, Energy Services	2002 – 2003
Senior Vice President, Corporate Development and Strategy	2002
Vice President, New Ventures and Corporate Development	2000 – 2002
American Electric Power Company, Inc. (Holding company for electricity generation and distribution operations)	

* Years of service includes years of service as a director of Peoples Energy Corporation prior to the merger with Integrys Energy Group, Inc., in 2007.

(3) Ms. Collins also currently serves on the board of directors for the following publicly held companies: PrivateBancorp, Inc. and Ulta Salon, Cosmetics & Fragrances, Inc. She has also served on the board of directors for the following publicly held companies within the last five years: Bucyrus International, Inc., and Molex, Inc. She has also served as a trustee for the following registered investment funds within the last five years: Wanger Advisors Trust and Columbia Acorn Trust.

(4) Mr. Jones also currently serves on the board of directors for the following publicly held companies: A.O. Smith Corporation, Federal Signal Corporation and Rexnord Corporation. He has also served on the board of directors for the following publicly held company within the last five years: Bucyrus International, Inc.

(5) Ms. Keller Koeppel also currently serves on the board of directors for the following publicly held company: Reynolds American Inc.

Name	Age	Director's Qualifications	Years
Michael E. Lavin (6)	68	Director Integrys Energy Group, Inc. Midwest Area Managing Partner Audit Partner KPMG, LLP (Public accounting firm)	2003 – present * 1993 – 2002 1977 – 2002
William F. Protz, Jr.	70	Director Integrys Energy Group, Inc. Consultant President and Chief Executive Officer Santa's Best LLP (Manufacturer of Christmas decorations and accessories)	2001 – present 2003 – 2006 1991 – 2003
Charles A. Schrock	61	Director, Chairman and Chief Executive Officer Director, Chairman, President and Chief Executive Officer Director, President and Chief Executive Officer Integrys Energy Group, Inc. President and Chief Executive Officer President President and Chief Operating Officer – Generation Wisconsin Public Service Corporation	2014 – present 2010 – 2013 2009 – 2010 2008 – 2009 2007 – 2008 2004 – 2007

* Years of service includes years of service as a director of Peoples Energy Corporation prior to the merger with Integrys Energy Group, Inc., in 2007.

(6) Mr. Lavin has served on the board of directors for the following publicly held company within the last five years: Tellabs, Inc.

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The table below sets forth certain information regarding our executive officers, as of December 31, 2014:

EXECUTIVE OFFICERS OF INTEGRYS ENERGY GROUP

Name and Age [1]		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	61	Chairman and Chief Executive Officer	01-01-14
		Chairman, President and Chief Executive Officer	04-01-10
		President and Chief Executive Officer	01-01-09
Lawrence T. Borgard	53	President and Chief Operating Officer – Integrys Energy Group	01-01-14
		President and Chief Operating Officer – Utilities	04-05-09
Charles A. Cloninger	56	Executive Vice President, Electric Segment	05-15-14
		President – Wisconsin Public Service	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	01-01-13
		Executive Vice President – Business Performance and Shared Services	12-26-10
		Executive Vice President – Corporate Development and Shared Services	09-21-08
William E. Morrow	58	Executive Vice President, Gas Segment	05-15-14
		Vice President – Gas Engineering – Integrys Business Support	07-07-08
Mark A. Radtke	53	Executive Vice President – Shared Services and Chief Strategy Officer	01-01-13
		Executive Vice President and Chief Strategy Officer	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	05-15-14
		Vice President and Chief Financial Officer	01-01-13
		Vice President – External Affairs	03-22-10
		Vice President – Regulatory Affairs	07-18-04
Daniel J. Verbanac	51	Executive Vice President – Integrys Business Support	11-01-14
		President – Integrys Energy Services	01-01-10
		Chief Operating Officer – Integrys Energy Services (previously named WPS Energy Services)	02-15-04
Linda M. Kallas	55	Vice President and Controller	05-16-13
		Vice President and Corporate Controller	09-01-12
		Vice President of Finance and Accounting Services	06-06-07
William J. Guc	45	Vice President and Treasurer	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	05-15-14
		Vice President – Human Resources and Corporate Communications	01-01-13
		Vice President – Human Resources	09-21-08
Jodi J. Caro	49	Vice President, General Counsel and Secretary	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 listed above are related by blood, marriage, or adoption to any of our 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.

Corporate Governance Matters

Code of Conduct and Governance Guidelines

We have a Code of Conduct, which 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, Corporate Controller, and any other persons performing similar functions. We have also adopted Corporate Governance Guidelines.

Our Code of Conduct, Corporate Governance Guidelines, and charters of our board committees may be accessed on our website at www.integrysgroup.com by selecting "Investors," then selecting "Corporate Governance," then selecting "Governance Documents." Our Code of Conduct 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 the website within the prescribed time period.

Audit Committee

As of December 31, 2014, the audit committee consisted of four independent directors as follows: Ellen Carnahan, Michelle L. Collins, Paul W. Jones, and Michael E. Lavin - Chair.

The board of directors has determined that all members of the audit committee are financially literate pursuant to New York Stock Exchange requirements and also meet the audit committee financial expert requirements as defined by the SEC. Ms. Carnahan currently serves on the audit committee of The JNL Funds, a registered investment company. Ms. Collins currently serves on the audit committee of Ulta Salon, Cosmetics & Fragrances, Inc. and also served on the audit committees of Columbia Acorn Trust and Wanger Advisors Trust, both registered investment companies, until October 2014.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers, directors, and persons who beneficially own more than 10% of our common stock to file reports of changes in ownership of our common stock with the SEC within 2 business days following such change. We have reviewed statements of beneficial ownership furnished to us and written representations made by our executive officers and directors. Based solely on this review, we believe that our executive officers and directors timely filed all reports they were required to file under Section 16(a) in 2014 except for William J. Protz, Jr., who reported one transaction late.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

A discussion and analysis of our executive compensation program is set forth below. We believe that our executive compensation program appropriately aligns pay with performance and plays a key role in achieving our business goals and creating shareholder value as well as supporting our values and beliefs.

All important aspects of our executive compensation program are discussed below, including our overall compensation philosophy, pay for performance, and how our board of directors' compensation committee (which is comprised of independent directors) establishes and administers our executive compensation program. Our discussion and analysis focuses on each of the key components of our executive compensation program during 2014 for the following named executive officers:

- Charles A. Schrock, Chairman and Chief Executive Officer (CEO)
- James F. Schott, Executive Vice President and Chief Financial Officer (CFO)
- Lawrence T. Borgard, President and Chief Operating Officer – Integrys Energy Group
- Phillip M. Mikulsky, Executive Vice President – Corporate Initiatives and Chief Security Officer
- Mark A. Radtke, Executive Vice President – Shared Services and Chief Strategy Officer

As previously discussed, on June 22, 2014, we 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

In designing and administering our executive compensation program, the compensation committee is guided by an overall philosophy that emphasizes pay for performance and includes the following key objectives:

- Reward executive performance consistent with our business objectives, including operational effectiveness and financial results, which in turn should create value for our shareholders, and reduce the need for, or the size of, rate increases for our utility customers;
- Align executive efforts with our core values of integrity, innovation, safety, collaboration, respect for employees, service to customers, value creation for our shareholders and support for the communities we serve;
- Attract, retain, motivate, and develop a highly qualified executive staff;
- Provide a mix of fixed and variable pay, as well as a mix of short-term and long-term incentives to appropriately balance executive focus on short-term and long-term goals and avoid excessive risk-taking; and
- Provide a mechanism for executives to have a stake in the company through stock ownership.

These objectives are embedded in the design of our executive compensation program in a way that we believe rewards performance, reinforces the right behaviors, and contributes to short-term and long-term positive financial performance. They also help us attract and retain highly qualified executives who are committed to the long-term success of the company and value creation for our shareholders.

We implement our executive compensation philosophy through the following programs:

Compensation	Program	Objectives Achieved	Fiscal 2014 Actions
	Base Salary	• Market-Competitive Compensation (targeted at 50th percentile) to Attract Highly Qualified Executives	• 2.6% general wage increase for named executive officers (NEOs) other than Mr. Schott and Mr. Borgard, who both received a 10% increase, to bring their base pay closer to market median
Annual Cash Compensation	Short-Term Incentive Plan with goals based on: • Financial metrics of Diluted Earnings Per Share (EPS) – Adjusted – 70% weighting • Nonfinancial metrics are safety, customer satisfaction, and environmental impact – 30% weighting	• Reward for Company Performance • Market-Competitive Compensation to Attract Highly Qualified Executives • Shareholder Alignment	• Financial metric derived from earnings per share • Target annual incentive opportunity unchanged for all NEOs except Mr. Borgard's which increased 5%, Mr. Schott's which increased 10%, and Mr. Radtke's which decreased 5% in order to bring their annual incentive targets closer to market median
Long-Term Incentive Compensation	Long-Term Incentive Plan with three award types: • Performance Shares tied to Total Shareholder Return – 60% weighting • Stock Options – 20% weighting • Restricted Stock Units – 20% weighting	• Reward for Company Performance • Market-Competitive Compensation to Attract Highly Qualified Executives • Retention • Shareholder Alignment	• Long-term incentive opportunity unchanged for all NEOs except for Mr. Borgard's which increased 25% and Mr. Schott's which increased 20% in order to bring their long-term incentive target closer to market median
Benefits	Retirement/Health, Welfare, and Other Benefits	• Market-Competitive Compensation to Attract Highly Qualified Executives • Retention	• Unchanged from prior year.

In addition to these compensation programs, we have a change in control program for our executive officers. Our change in control program incorporates “double triggers,” which provide executive officers compensation if there is a change in control and the executive officer is either terminated without cause or the executive leaves for “good reason,” as defined in our program documentation. We believe our change in control program helps us retain talented executives who actively seek to maximize shareholder value, even if it means pursuing a transaction that might result in their termination.

Overview of 2014 Business Results and Performance-Based Compensation

Overall, business conditions for 2014 remained challenging. Similar to 2013, in which most of our executives received a 3% increase in base pay, our compensation committee approved a base pay increase of 2.6% for 2014 for all of our named executive officers, except Mr. Borgard and Mr. Schott, who each received a 10% increase in order to bring their base pay closer to the market median.

Most of the short-term incentive compensation for our named executive officers is tied to financial performance, with 70% of the incentive tied to the Diluted EPS – Adjusted measure for all of our named executive officers. As reflected below, the Diluted EPS – Adjusted measure was below threshold and resulted in no payout for that portion of the award:

Overall, our performance results for the nonfinancial measures, which comprise 30% of the short-term incentive target for all of our named executive officers, were below expectations with environmental coming in below threshold, safety results being between threshold and target and customer satisfaction coming in between target and superior. Additional information regarding our nonfinancial measures can be found below under the heading "Key Components of our Executive Compensation Program – Short-Term Incentive Compensation."

For the February 2012 performance share grant (performance for the three-year period ending December 31, 2014), which represents 60% of the target long-term incentive opportunity for all of our named executive officers, our Total Shareholder Return (TSR) ranked at the 68^{th} percentile relative to the performance share comparator group. As a result, our named executive officers earned 136% of the target award under the terms of the plan related to the 2012-2014 performance period.

Executive short-term incentive payouts fluctuated over the three years preceding 2014, with average payout percentages based on a targeted incentive for our named executive officers of 67.01% in 2011, 28.27% in 2012, and 119.93% in 2013. Performance share payouts for the multi-year cycles ending in 2011, 2012, and 2013 were 74%, 130%, and 0% of target payouts based on relative TSR performance.

Actions Taken in 2014 in Light of Proposed Merger

In light of the proposed merger, we took certain actions to accelerate the vesting and/or payment of certain equity or incentive compensation benefits, to provide us and our designated employees, including the 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 the 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, we paid to designated employees, including the 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 compensation committee. Because the final short-term 2014 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.

Outlook for our 2015 Executive Compensation Program

We expect that we will need to continue to work diligently to achieve our business goals in 2015. We have worked to ensure that our executive compensation program remains consistent with our compensation philosophy and is structured to help us achieve our goals. In developing compensation plans for fiscal year 2015, the compensation committee considered the positive “say on pay” vote of our shareholders at our 2014 annual meeting of shareholders. Taking into consideration the results of the shareholder vote, and as we further describe in this Compensation Discussion and Analysis, the compensation committee has kept in place for 2015 similar executive compensation program components as were disclosed in our 2014 proxy statement except that 2015 equity awards will be made exclusively as restricted stock unit awards. Accordingly, stock options and performance shares will not be utilized in our 2015 executive compensation program. The compensation committee will continue to regularly review our executive compensation program throughout 2015, including monitoring rule-making developments related to the 2010 Dodd-Frank financial reform legislation.

Role of the Compensation Committee and Advisors to the Committee

Purpose and Membership in 2014

The compensation committee of the board of directors has the authority to set policy for our executive compensation program, and to establish and administer the executive compensation program for the company and its subsidiaries consistent with our compensation philosophy. The compensation committee consisted of:

- William J. Brodsky
- Kathryn M. Hasselblad-Pascale
- John W. Higgins, Chair
- Michael E. Lavin

Decision-Making Process

The compensation committee generally adheres to objective criteria and a structured method of determining compensation, with discretionary decision-making in limited circumstances. Compensation decisions made by the compensation committee rely on market trends and performance at the corporate, business unit, and individual levels. The compensation committee also may review the compensation history of the named executive officers, but it is only a minor factor in setting future compensation for our named executive officers. The compensation committee reserves the right to modify or discontinue elements of the executive compensation program, and to revise compensation levels after considering qualitative and quantitative facts and circumstances surrounding actual or projected financial results, individual performance, market trends, as well as its view of the appropriate balance among base salary, annual short-term incentive compensation, long-term incentive compensation, and other benefits.

Use of Independent Compensation Consultant

The compensation committee engages an independent compensation consultant to evaluate executive compensation, to discuss general compensation trends, to provide competitive market data, and to assist our human resources department and our CEO in developing recommendations to present to the compensation committee. The compensation consultant provides the compensation committee with advice, consultation, and market information on a regular basis throughout the year. Only the compensation committee has the authority to continue or discontinue its relationship with the compensation consultant. In this regard, the compensation committee maintains frequent contact with the compensation consultant and regularly reviews the independence of and the performance of the consultant.

For 2014, the compensation committee engaged Exequity LLP (Exequity) as its independent executive compensation consultant. Exequity does not provide any other consulting services to the company, and the compensation committee has affirmatively determined that Exequity’s services have not raised any conflicts of interest.

Although the compensation committee’s compensation consultant provides a review of market data for consideration by the compensation committee in setting senior executive compensation levels and programs (including compensation levels and programs for our named executive officers), the compensation committee’s compensation consultant generally does not make specific recommendations on individual compensation amounts for our named executive officers other than the CEO, nor does the consultant determine the amount or form of executive compensation. Decisions on senior executive compensation levels and programs are recommended and/or made by the compensation committee, with approval as appropriate from the board of directors. The compensation committee and the full board of directors approve the use of all equity grants for executives as well as nonexecutives.

In performing its duties, the committee’s compensation consultant is instructed to perform independent research based on competitive market data of similarly sized companies in the utility/energy services industry and in the broader general industry. The committee’s compensation consultant uses both proprietary compensation surveys and the consultant’s knowledge of industry practices in its research. For 2014, the compensation committee’s compensation consultant assisted the compensation committee by providing a competitive compensation analysis of the company’s executive positions, an analysis of pay for performance, an overview of compensation trends and proposed legislation, a review of peer company executive benefits and perquisites, and reviews of various incentive plan practices.

Management’s Advisory Role

During meetings of the compensation committee, the CEO and certain other officers may be present when executive compensation considerations are discussed by the compensation committee. The Vice President and Chief Human Resources Officer and the CEO typically provide information and recommendations to the compensation committee for their consideration. Specifically, the CEO serves in an advisory role to the compensation committee regarding executive compensation for the named executive officers, other than himself. This includes discussion of executive performance (as described below in this section under the heading “Executive Performance”). In addition, the CEO participates in discussions on short-term incentive measures and performance levels for the company as a whole and for the named executive officers as a group, some of which may apply to the CEO’s short-term compensation. Although the CEO’s recommendations are given significant weight by the compensation committee, the compensation committee remains responsible for all decisions on compensation levels for the named executive officers as well as our executive compensation policies and programs. In fulfilling its responsibilities related to executive compensation, the compensation committee meets in executive session without management at each of its meetings and also meets in executive session at least annually with the compensation consultant.

The CEO provides the compensation committee with an assessment of his own performance during the year. However, the CEO does not make recommendations with regard to his own pay and is not present when his own compensation is considered. Rather, such discussions occur in executive session with the compensation committee's compensation consultant present and no management team members present.
In the CEO's advisory role to the compensation committee, he does not have the authority to call a meeting of the compensation committee.

Setting Compensation Levels

Benchmarking

Our objective is to use competitive market data to establish the total compensation target at or near the median level of a utility/energy industry peer group. This competitive market data is used to determine the compensation levels for the named executive officers and the key elements of their compensation. The compensation committee generally adheres to objective criteria and a structured method of determining compensation. To determine base salaries and equity grants for the named executive officers, the compensation committee relies primarily on median competitive market data. Occasionally the compensation committee may make minor adjustments to a named executive officer's compensation based on individual performance as discussed below in this section under the heading "Executive Performance." To the extent that base salaries and equity grants vary by professional role in the marketplace, the base salaries and equity grants of the named executive officers will vary, sometimes significantly. These variations are supported by the competitive market data reviewed and provided by the independent compensation consultant.
For example, consistent with the level of responsibility and the executive compensation practices of the companies in the market data discussed below, CEOs typically earned significantly more in base salary, annual incentive, and long-term incentive equity grants than other named executive officers. This resulted in our CEO being eligible to receive a higher percentage of base salary in annual and long-term incentives than our other named executive officers.

The compensation committee uses information from its compensation survey and performance peer groups, as well as other market data that it deems appropriate, to ensure that our executive compensation program will achieve its desired goals. For the purposes of reviewing and setting compensation for 2014, the compensation committee used a utility/energy industry peer group developed by its independent outside compensation consultant to review competitive market data. The utility/energy industry peer group is reviewed annually and adjusted if necessary, to reflect changes such as acquisitions of peer companies. The objective is to develop a peer group that corresponds with our size and scope in the utility/energy industry. For 2014, the utility/energy industry peer group was comprised of the following companies:

AGL Resources Inc.	MDU Resources Group, Inc.	Portland General Electric Company
Alliant Energy Corporation	Northeast Utilities System	SCANA Corporation
Ameren Corporation	NorthWestern Corporation	TECO Energy, Inc.
Atmos Energy Corporation	NV Energy, Inc.	UGI Corporation
Avista Corporation	OGE Energy Corp	Vectren Corporation
Black Hills Corporation	Pepco Holdings, Inc.	Westar Energy, Inc.
CenterPoint Energy, Inc.	Pinnacle West Capital Corporation	Wisconsin Energy Corporation
CMS Energy Corporation	PNM Resources, Inc.	Xcel Energy Inc.
DTE Energy Company		

With respect to the utility/energy industry peer group, we generally review only aggregate data (i.e., 25^{th}, 50^{th}, and 75^{th} percentiles) and do not review data specific to an individual company. We intend to continue our strategy of compensating our named executive officers at market-competitive levels, with an opportunity to earn above-median compensation for above-market performance or, in the alternative, to earn less than market for below-market performance. This is achieved through programs that emphasize performance-based incentive compensation in the form of cash and equity-based awards. To that end, total executive compensation for our named executive officers is tied directly to performance and is structured to ensure that, due to the nature of our business, executive focus is appropriately balanced between short-term and long-term performance, so that shareholder value can be maximized with appropriate focus on risk management.

Based on our analysis, we believe that the total compensation paid or awarded to our named executive officers during 2014 was consistent with our financial and operational performance and the individual performance of each of our named executive officers. We also believe that the total compensation was reasonable and is consistent with our compensation philosophies as described above.

Executive Performance

The compensation committee reviews each named executive officer’s individual performance, other than the CEO’s, with the CEO in setting the named executive officer’s compensation levels. Short-term incentive payouts are typically based on company performance results, and not on individual performance. For those compensation components where individual performance is a consideration, individual performance is considered and may result in adjustments to compensation levels.

As part of assessing named executive officers' individual performance each year, the compensation committee considers information provided by the CEO regarding the named executive officers (other than himself) throughout the year. The primary assessment of named executive officer performance normally occurs during an executive session at the compensation committee's December meeting. During this session, the CEO reviews the individual performance of the other named executive officers. Our CEO summarizes information to be included in the annual performance review that is provided to each named executive officer. The annual performance review for each named executive officer reflects an assessment of how well the named executive officer fulfilled his or her executive responsibilities, achieved assigned goals, and demonstrated core competencies. Core competencies include, but are not necessarily limited to, facilitating and managing change, building and sustaining relationships, leading a successful team, coaching, motivating and developing others, strategic leadership, and business acumen. In addition to summarizing the individual performance of a named executive officer as reflected in the officer's annual performance review, our CEO also reviews with the compensation committee, as appropriate, the named executive officer's contributions to (1) our financial and operational results, (2) achievement of our customer service goals, (3) advancing our core values, (4) developing leaders, and (5) succession planning.

The compensation committee in conjunction with the Lead Independent Director also reviews and discusses the CEO's annual performance in executive session at its December meeting, and periodically throughout the year as needed. During these discussions, the CEO is not present but does provide the compensation committee with an assessment of his own performance during the year. The compensation committee's determination as to the CEO's individual performance is reviewed by the full board of directors. The CEO is also excused from the discussion that the board of directors has regarding the CEO's performance, although the board of directors does review its conclusions with the CEO.

Consideration of Risks Associated with Our Executive Compensation Program

In formulating and evaluating material elements of compensation available to our named executive officers, the compensation committee takes into consideration whether any such programs may encourage our named executive officers to take excessive risks. As part of these considerations and consistent with its compensation philosophy, the compensation committee is determined to formulate annual and long-term incentive compensation programs that do not encourage excessive risk taking as an inherent part of the applicable plan design. The compensation committee believes that our current annual and long-term incentive programs discourage excessive risk taking by our named executive officers, in that:

- Significant compensation elements under both plans include stock-based compensation with multiple-year vesting periods along with stock-ownership guidelines;
- The financial metrics utilized are based on earnings per share, focusing on continuing business operations with results adjusted from GAAP in accordance with the plan design, and are widely utilized measurements of shareholder value;
- No changes to short-term or long-term incentive program financial goals are made after the initial establishment of such elements by the compensation committee;
- The nonfinancial metrics utilized focus on operational results tied to delivering timely and quality services to customers in a safe and environmentally friendly way;
- Excessive compensation payment opportunities are avoided due to plan design and limitations on payout levels;
- The annual incentive is based on multiple measures, both financial and nonfinancial;
- The committee approves both the plans and the payouts under the plans; and
- Salaries are competitive with market and are a basic element of overall compensation.

Consideration of Tax and Accounting Matters

Our compensation committee has considered the implications of Section 162(m) of the Internal Revenue Code in making decisions concerning compensation design and administration. Our compensation committee views tax deductibility as an important consideration and intends to maintain deductibility wherever possible, but also believes that our business needs should be the overriding factor in compensation design. Therefore, the compensation committee believes it is important to maintain flexibility and has not adopted a policy requiring that specific programs meet the requirements of performance-based compensation under Section 162(m). Our compensation committee also considers tax implications for executives and structures its compensation programs to comply with Section 409A of the Internal Revenue Code. Accounting and cost implications of compensation programs are considered in program design; however, the main factor is alignment with our business needs.

Key Components of our Executive Compensation Program

The key components of our executive compensation program are base salary, annual short-term incentive compensation, long-term incentive compensation and other benefits. In this mix of compensation, at-risk compensation is a significant portion of total compensation. Base salary can be less than one-half of overall compensation received by our named executive officers, as shown in the chart below. Short-term and long-term incentives make up the remainder of direct compensation and, except for restricted stock units, are performance-based, with a greater weighting on long-term incentives. We are placing a greater weighting on long-term incentives because we believe that this most effectively encourages our executive officers to work to generate long-term shareholder value. We also believe that this weighting better aligns the interests of our executive officers with our long-term interests, by discouraging undue risk-taking, promoting ownership in the company, and encouraging retention.
All matters discussed below pertain to our executive compensation program that was in place during 2014.

Base Salary

Base salary is used to provide cash income to executives to compensate them for services rendered during the fiscal year. At least annually, the compensation committee's compensation consultant reviews competitive market benchmark data with the compensation committee. Market comparisons are based on the median (50^{th} percentile) base salary for substantially equivalent positions at companies in the utility/energy industry peer group. Salary increases for 2014 were determined by the compensation committee based on recommendations of the CEO, which may include overall company performance and individual performance of the executive as discussed above, and the compensation committee's evaluation of current market data as provided by the independent executive compensation consultant hired by the compensation committee. In December 2013, the compensation committee granted a base salary increase for 2014 of 2.6% for all of the named executive officers except 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 the 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 (referred to as the incentive plan). The purpose of the incentive plan is to:

- Focus executive employees on assisting the company in achieving objectives key to its success;
- Recognize the leadership of key employees in achieving our financial and operating objectives; and
- Provide compensation opportunities that closely reflect the pay levels at companies in the utility/energy industry peer group.

Annual incentive payments under the incentive plan are based on financial and nonfinancial performance goals. The overall target payout for the named executive officers is established based on the utility/energy industry peer group market median (50^{th} percentile). We consider stretch performance objectives in determining performance measures and payout levels. Payout levels provide a reduced payout for partially meeting objectives (above threshold performance levels) and a strong incentive, generally two times target level, for superior performance.

Our incentive plan provided short-term incentive compensation for our named executive officers based on the attainment of the performance goals and weightings described below:

	Schrock	Schott	Borgard	Mikulsky	Radtke
Financial Goals					
Diluted EPS – Adjusted [(1)]	70%	70%	70%	70%	70%
Nonfinancial Goals					
Environmental Impact [(2)]	10%	10%	10%	10%	10%
Customer Satisfaction – Utility Customers [(3)]	10%	10%	10%	10%	10%
Safety [(4)]	10%	10%	10%	10%	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 determined on an Integrys Energy Group consolidated basis.

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 recommended by the human resources department, CFO and CEO (excluding his own) based on historical results, anticipated business conditions, and goals and objectives of the company. After considering these recommendations, as well as the input of the independent compensation consultant, the compensation committee determines the final levels. For each of the short-term incentive measures, the compensation 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 each of our named executive officers for the incentive plan:

	Payout Levels (as a Percent of Actual Paid Base Salary)		
Named Executive Officer	Threshold	Target	Superior
Charles A. Schrock	0	100.0	200.0
James F. Schott	0	60.0	120.0
Lawrence T. Borgard	0	75.0	150.0
Phillip M. Mikulsky	0	60.0	120.0
Mark A. Radtke	0	60.0	120.0

Provided below are threshold, target, and superior levels, as well as information related to actual results achieved for 2014 and related payout percentages for our financial measures:

Financial Measure	Threshold	Target	Superior	2014 Actual Results Amount	2014 Actual Results 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 compensation committee at the beginning of the year, the compensation 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. These types of 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 compensation committee were consistent with the types of adjustments allowed under the incentive plan.

The 2014 nonfinancial measures and performance range results 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 our named executive officers for 2014, along with payout percentages as a percent of targets and individual base salary earnings, are summarized in the following table:

	Schrock	Schott	Borgard	Mikulsky	Radtke
Amount of Payout	$92,632	$25,662	$44,252	$26,525	$24,430
Payout as a Percent of Target	9.86 %	9.86 %	9.86 %	9.86 %	9.86 %
Payout as a Percent of Base Salary	9.86 %	5.92 %	7.39 %	5.92 %	5.92 %

We believe 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. 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 120.09% of target and from 5.92% to 120.09% of actual paid base salary during the 2012 through 2014 plan performance periods.

Long-Term Incentive Compensation

We believe that equity-based compensation ensures that our executives have a continuing stake in the long-term success of the company and also serves to discourage undue risk-taking for only short-term gain. In a manner consistent with our overall compensation philosophy, we have adopted certain long-term compensation plans that utilize various equity-based compensation awards, including performance shares, nonqualified stock options, and restricted stock units.

For long-term incentive awards granted to our named executive officers in February 2014, long-term incentive compensation was comprised of 60% performance share awards, 20% nonqualified stock options, and 20% restricted stock units. This mix is intended to provide balance between performance-oriented long-term incentive vehicles (performance shares and stock options) and retention-oriented long-term incentive vehicles (restricted stock units). While we also consider the mix of long-term incentives provided by our benchmark companies, we primarily structure the long-term incentive mix based on compensation objectives of the company. The amount of total long-term incentive received by each named executive officer is determined by the compensation committee and recommended to the board of directors, which relies on the market median data reviewed by the compensation committee. The compensation consultant provides the market median data to the compensation committee based on the benchmarking comparator group. In addition, the performance of each named executive officer may be considered, as discussed above.

The target value of the aggregate long-term incentive compensation granted for 2014 as a percent of annualized base salary for each named executive officer was 250% for Charles A. Schrock, 130% for James F. Schott, 200% for Lawrence T. Borgard, 125% for Phillip M. Mikulsky, and 133% for Mark A. Radtke. These grants were made as performance shares, nonqualified stock options, and restricted stock units, as discussed below.

Performance Shares

We believe that the granting of Integrys performance shares encourages our named executive officers to direct their efforts in a manner consistent with the optimization of total shareholder return (TSR), and to create shareholder value that is superior to that of the company’s peers.
Performance share awards are based on TSR over a three-year period. During the three-year period, there are no dividends paid to participants nor do participants have voting rights over the shares subject to the award. Performance shares represent 60% of the total long-term incentive opportunity for each named executive officer. At the end of the three-year period, the compensation committee makes a relative comparison of the company’s TSR to the TSR of the performance share comparator group selected by the compensation committee for the three-year period, and determines the number (if any) of performance share awards to issue. The performance share comparator group used to determine the number of shares earned consists of all energy/utility companies that are included in the Standard & Poor’s 1500 Index on both the first and last day of the performance period (approximately 60 energy/utility companies). At the end of a performance period, the compensation committee makes a recommendation to the board of directors regarding the amount of payout based on this method of measuring performance.

The number of shares to be provided at target is based on market median levels of incentive compensation, competitiveness of the total compensation package, and individual performance. A new three-year performance period starts annually. If our TSR is at the 50^{th} percentile (target level) of the performance share comparator group, as determined by the compensation committee, a payout of 100% of target award is made. If our TSR is at the 25^{th} percentile (threshold level), a payout of 50% of the target award is made. If our TSR is below the 25^{th} percentile, no payouts are made. If our TSR is at the 90^{th} percentile (superior level), a payout of 200% of the target award is made. If our TSR results are in between the threshold, target, and superior levels, payouts are determined based on interpolation. For the February 2012 performance share grant (performance period ended on December 31, 2014), our TSR ranked at the 68^{th} percentile, relative to the performance share comparator group. As a result, our named executive officers earned a payout award under the terms of the plan related to the 2012-2014 performance period. Final approval of the outcome is made by the board of directors after considering the recommendation of the compensation committee.

Nonqualified Stock Options

We believe that the granting of company stock options serves to encourage the named executive officers to direct efforts that will ultimately lead to an increase in shareholder value. The number of stock options granted is based on market median levels of incentive compensation, competitiveness of the total compensation package, individual performance, and the desired mix of long-term incentive awards. The number of stock options granted represents 20% of the total long-term incentive opportunity for each named executive officer. Consistent with the plan document, option grants have strike prices equal to the closing market price of a share of common stock on the date the options are granted. One quarter of the options granted vest each year on the grant anniversary date. All options have a 10-year term from the date of grant. There are no dividends or voting rights associated with stock options. Final approval of grants is made by the board of directors after considering the recommendation of the compensation committee.

Restricted Stock Units

We believe that the granting of restricted stock units serves to increase retention of executives, establishes an incentive to continually improve TSR, and provides another alternative for executives to increase stock ownership in our company, all of which are intended to increase shareholder value. The number of restricted stock units granted is based on market median levels of incentive compensation, competitiveness of the total compensation package, individual performance, and the desired mix of long-term incentive awards. The number of restricted stock units granted represents 20% of the total long-term incentive opportunity for each named executive officer. The company’s restricted stock units have a four-year vesting schedule (25% per year), and do not give the named executive officers voting rights until vested. With respect to the restricted stock units granted in 2014, dividends are deemed to be reinvested in additional restricted stock units, which are released according to the vesting schedule. Final approval of grants is made by the board of directors after considering the recommendation of the compensation committee.

Other Benefits and Plans

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

Deferred Compensation Plan

Our named executive officers may participate in the nonqualified Integrys Energy Group, Inc. Deferred Compensation Plan (referred to as the deferred compensation plan) with the approval of the compensation committee. 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 stock options) on a pre-tax (federal and state) basis. The deferred compensation plan also provides for a matching contribution credit for any reduction in the matching contribution the executive receives under the Employee Stock Ownership Plan (ESOP) due to the executive’s election to defer base salary or annual short-term incentive compensation to the deferred compensation plan.

Several investment types are available to eligible executives, as listed below:

- Reserve Account A – This option is no longer available after 1995 for additional deferrals. Money previously deferred to Reserve Account A receives accrued interest based on the greater of 6.0% or our consolidated return on common equity, as calculated on April 1 and October 1 each year. This account is currently providing an above-market rate of return of 11.09%, which exceeds 120% of the applicable federal long-term rate of 3.47%. An executive may transfer amounts from Reserve Account A to another available investment option, but once transferred, the amounts cannot be allocated back to Reserve Account A.
- Reserve Account B – This option is no longer available for deferrals made after March 31, 2008. This account provides for an interest accrual equal to the greater of 6.0% or 70% of our consolidated return on common equity. This account is currently providing an above-market rate of annual return of 7.89%, which exceeds 120% of the adjusted applicable federal long-term rate of 3.47%. An executive may transfer amounts from Reserve Account B to another available investment option, but once transferred, the amounts cannot be allocated back to Reserve Account B.
- "Mutual Fund" Account – This option is available for base compensation and annual incentive deferrals and, effective April 1, 2008, performance share deferrals. These options generally provide the executive with the ability to elect the same investment funds provided by the Integrys Energy Group 401(k) Plan for Administrative Employees.
- Locked Stock Unit Account – This is a company stock unit account to which is credited deferrals that an executive is not allowed to convert to other investment types. This includes pre-April 1, 2008, deferrals related to grants from long-term performance shares, deferrals of restricted

stock or restricted stock units that became vested prior to April 1, 2008, annual incentive award payouts with respect to which the executive received a 5% premium for amounts allocated to stock units, and the pre-2008 ESOP matching contribution credit to replace company contributions that would have normally been made to the ESOP except for the executive's deferrals to the deferred compensation plan. Deferrals into this account are not allowed to be converted to other investment types. This account also holds unvested deferred restricted stock units with vesting dates on or after April 1, 2008; upon vesting, these amounts are transferred to the Discretionary Stock Unit Account discussed below.

- Discretionary Stock Unit Account – This is a company stock unit account available for deferrals that may be transferred to or from this account from another available option, or vice versa.

Base compensation deferrals may be changed one time per year prior to the beginning of each calendar year. Deferrals of annual short-term or long-term incentive compensation must be made in accordance with rules prescribed by the compensation committee, which generally require that the executive's election be in place either prior to the beginning of the calendar year in which the award is granted (with respect to awards that are subject to time-based vesting) or at least six months prior to the last day of the incentive performance period (in the case of eligible performance-based awards). The rates of return on the investment accounts ranged from (5.79%) to 49.19% for the 12-month period ending December 31, 2014. More information regarding contributions, earnings, and balances held by each of our named executive officers is presented in the Nonqualified Deferred Compensation Table for 2014.

Qualified Pension Plan

Our named executive officers are eligible to participate in the qualified Integrys Energy Group, Inc. 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.

The pension income benefit under the pension plan is equal to the "total service percent" multiplied by "final average pay." The pension income benefit consists of a lump sum benefit, which may be converted into an actuarially equivalent annuity with monthly payments. "Final average pay" is the average of the last 60 months or the 5 highest calendar years' compensation within the 10-year period immediately preceding the participant's termination of employment, whichever is greater, up to IRS pay limits. Eligible compensation considered under the plan includes base salary, annual short-term incentive payout, and bonuses. The "total service percent" for eligible service-based annual accruals varies from 9% to 15% per year (9% to 13% for employees hired after January 1, 2001), depending on the number of years of service. Participants actively employed on January 1, 2001, earned a pension transition benefit based on age and service, up to 115% of final average pay.
In addition, if an employee who was hired prior to January 1, 2001, terminates employment on or after attainment of age 55 (but prior to 65) and completion of five or more years of service, the plan provides for a monthly supplemental benefit equal to $800 per month payable until age 65. For an employee hired on or after January 1, 2001, the pension supplement is available if the employee terminates employment on or after attainment of age 55 (but prior to 65) and completes 10 or more years of service, and consists of a monthly benefit payable until age 65 equal to $40 times the years of credited service, up to a maximum of 20 years. If the pension income benefit is paid in a lump sum, the pension supplement is automatically converted into and paid at the same time as an actuarially equivalent lump sum.

Only service through December 31, 2012, and compensation through December 31, 2017, will be recognized in calculating benefits. Effective January 1, 2013, service for calculating pension benefits has been frozen. Employees hired on or after January 1, 2008, are not eligible for the pension plan.

Provided below is the pension service credit for each of our named executive officers:

Named Executive Officer	Accumulated Total Earned as of	Service Credits

	December 31, 2014	
Charles A. Schrock	514	%
James F. Schott	90	%
Lawrence T. Borgard	410	%
Phillip M. Mikulsky	651	%
Mark A. Radtke	431	%

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 for each of our named executive officers, using full years of credited service only.

Pension Restoration and Supplemental Retirement Plan

Our named executive officers receive nonqualified pension restoration benefits and all named executive officers other than Mr. Schott receive nonqualified supplemental retirement benefits under the nonqualified Integrys Energy Group, Inc. Pension Restoration and Supplemental Retirement Plan. In the ensuing discussion and in the Nonqualified Deferred Compensation Table for 2014 below, we refer to the pension restoration benefit portion of this plan as the pension restoration plan, and we refer to the supplemental retirement benefit portion of this plan as the SERP.

Pension restoration benefits are 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 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 each named executive officer.

Supplemental retirement benefits provide income replacement when taking into account other retirement benefits provided to the named executive officer and ensures that the named executive officer will receive 60% of final average pay (calculated to include both base salary and short-term incentive compensation payments 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.

The pension restoration and SERP benefits are designed to help retain key management employees who are important to the successful operation of the company. The Pension Benefits Table for 2014 below provides information regarding the present value of accumulated benefits under the pension restoration plan and the SERP for each named executive officer.

Beginning in 2008, we made the decision to move away from the use of defined benefit pension plans for all nonunion employees, including executives, because of market trends. A 10-year transition period applies, which means that for new nonunion employees hired after 2008, no qualified and 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 James F. Schott (who is 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 3 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 3 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 as of December 31, 2014, for each named executive officer:

Named Executive Officer	Life Insurance Coverage ($)
Charles A. Schrock	1,500,000
James F. Schott	1,322,000
Lawrence T. Borgard	1,500,000
Phillip M. Mikulsky	1,352,000
Mark A. Radtke	1,245,000

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

As part of our change in control program, we have had change in control agreements in place for a long period of time. These agreements are important to ensuring that our named executive officers actively seek to maximize shareholder value, even if it means pursuing a transaction that might result in their termination. Before we entered into the change in control agreements, we engaged a compensation consultant to provide information and advice as to what were competitive payments, benefits, terms and conditions of change in control agreements at that time (we discuss below our ongoing evaluation of these agreements). We then used this information to structure payment and benefit levels that were competitive in the marketplace, along with appropriate triggers.

The compensation 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 the company. The agreement with our named executive officers contains 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. Specifically, benefits under such an agreement would be triggered if both of the following occur: 1) a change in control event occurs in which a single entity takes ownership of 30% or more of our voting securities, a merger or sale occurs that results in Integrys Energy Group stock constituting less than 50% of the surviving company stock, or a merger or consolidation occurs where the company is not the surviving company; and 2) the event results in the loss of the executive's job or the executive incurs a significant adverse change in his or her working conditions or status compared to the executive's prior position and the executive terminates employment as a result. The agreement also contains confidentiality and noncompete clauses.

For specific details regarding change in control benefits, including in relation to the proposed merger, please see the discussion below under the heading "Termination of Employment."

The compensation committee periodically reviews the payment and benefit levels in our change in control program and the triggers to ensure that the payment and benefit levels remain competitive and appropriate. In conjunction with a review in 2010, the change in control agreements were modified to bring the agreements more in line with market practice, including: 1) reducing the period of protection following the change in control from three to two years following a change in control; 2) reducing the period for which certain welfare benefits would continue following termination from three years to two years; and 3) providing the same level of severance protection (i.e., 2.99 times base and target bonus) for qualifying terminations occurring at any time within the two-year period following a change in control.

In addition to modifying the agreements in 2010, the compensation committee also decided to adopt a change in control plan for use with newly appointed executive officers going forward. The change in control plan provides for change in control benefits similar to those available under the change in control agreements, which remain in place for previously appointed executive officers. The change in control plan does not include a gross up provision. The change in control plan is subject to amendment at the discretion of the Company. All of the current named executive officers are covered by change in control agreements except for Mr. Schott who is covered by the change in control plan, as he was first appointed an executive officer in 2010.

Since 2010, the compensation committee has continued to review the program annually and it continues to believe that the change in control program meets the Company's objectives and remains consistent with current market practices.

Common Stock Ownership Guidelines

We believe that it is important to align executive and shareholder interests by defining stock ownership guidelines for our executives. As a result, named executive officers are expected to retain at least 50% of their future vested stock awards until certain levels of stock are owned, with such levels generally ranging from two to five times base annual salary. Additionally, we have a policy that prohibits our named executive officers, as well as our directors and all other employees, from engaging in hedging transactions, trading in publicly traded derivatives involving our common stock, and other similar activities.

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 multiples of salary:

Named Executive Officer	Salary Multiple
Charles A. Schrock	5.00
James F. Schott	2.20
Lawrence T. Borgard	3.50

Phillip M. Mikulsky	2.50
Mark A. Radtke	2.66

Common stock beneficially held in an executive's ESOP account, any other beneficially owned common stock or common stock equivalents (including that awarded through incentive plan awards), common stock equivalents credited through nonqualified deferred compensation programs, and 50% of the difference between the past 12 months' average close and the strike price value of the vested stock options, are included in determining compliance with these guidelines. For purposes of determining compliance with our stock ownership guidelines, performance shares for which incentive targets have not yet been met are not included in the calculation of stock ownership until attainment of the incentive targets of performance shares are certified by the board of directors.

As of December 31, 2014, all named executive officers were in compliance with our stock ownership guidelines.

Summary Compensation Table for 2014

The following table sets forth information concerning compensation earned or paid to each of our named executive officers for each of the last three fiscal years consisting of (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. The named executive officers are our principal executive officer, principal financial officer, and our three other most highly compensated executive officers employed as of December 31, 2014.

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. Schrock	2014	939,627	—	1,786,247	495,277	92,632	2,012,628	524,378	5,850,789
Chairman and Chief	2013	915,815	—	1,381,636	517,133	1,099,796	17,506	294,225	4,226,111
Executive Officer	2012	892,085	—	1,679,109	476,822	256,790	2,768,544	21,812	6,095,162
James F. Schott (6) Executive	2014	433,846	—	433,272	120,131	25,662	65,429	171,688	1,250,028
Vice President and Chief Financial Officer	2013	397,097	—	264,479	98,995	238,435	30,740	129,894	1,159,640
Lawrence T. Borgard	2014	598,506	—	908,950	252,021	44,252	940,071	335,723	3,079,523
President and Chief Operating Officer	2013	542,382	—	572,796	214,385	452,275	717	199,536	1,982,091
– Integrys Energy Group	2012	523,283	—	696,111	197,675	105,369	1,285,148	18,138	2,825,724
Phillip M. Mikulsky	2014	448,425	—	426,258	118,181	26,525	267,196	213,959	1,500,544
Executive Vice President –Corporate	2013	437,061	—	329,686	123,398	314,918	70,072	142,711	1,417,846
Initiatives and Chief Security Officer	2012	425,737	—	400,693	113,778	73,530	434,763	23,808	1,472,309
Mark A. Radtke	2014	413,023	—	417,749	115,823	24,430	430,209	233,414	1,634,648
Executive Vice President – Shared	2013	402,557	—	323,113	120,932	314,228	—	145,042	1,305,872
Services and Chief Strategy Officer	2012	392,126	—	392,646	111,504	66,803	274,710	17,069	1,254,858

(1) Amounts shown include amounts deferred into the deferred compensation plan. For more information, see the Nonqualified Deferred Compensation Table for 2014 below.

(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. For information regarding the assumptions made in valuing the stock and option awards, see Note 23 - Stock-Based Compensation in Notes to Consolidated Financial Statements; such information is incorporated herein by reference.

(3) Nonequity compensation is normally payable in the first quarter of the next fiscal year, and a portion may be deferred at the election of the named executive officer. 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 the named executive officers 90% of the estimated 2014 short-term executive incentive award. In February 2015, the final 2014 short-term executive incentive award levels were calculated and certified by the compensation committee. Because the final 2014 short-term executive incentive award was greater than the amount paid in December 2014, the named executive officers 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.

(4) The amounts shown in relation to the change in pension value increased due to the decline in the overall interest rates. The amounts shown reflect the calculation of above-market earnings on nonqualified deferred compensation and 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, and 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 for each named executive officer include other compensation items consisting of life insurance premiums, imputed income from life insurance benefits, ESOP matching contributions, age and service 401(k) contributions, and employer nonqualified deferred compensation contributions. Individual items included in column (i) that were in excess of $10,000 include imputed income from life insurance benefits for Mr. Schrock of $11,484 and for Mr. Mikulsky of $19,761 and ESOP matching contributions, age and service 401(k) contributions, and employer nonqualified deferred compensation contributions for each named executive officer as follows:

Named Executive Officer	ESOP ($)	401(k) Age/Service ($)	Deferred Compensation ($)
Charles A. Schrock	17,927	18,200	475,507
James F. Schott	17,927	15,600	130,599
Lawrence T. Borgard	17,927	18,200	294,334
Phillip M. Mikulsky	17,927	18,200	156,941
Mark A. Radtke	17,927	18,200	192,661

(6) The amounts shown are only for 2013 and 2014, as Mr. Schott was not a named executive officer during 2012.

As discussed above in the Compensation Discussion and Analysis, in October 2014, all outstanding but unvested stock options held by the 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. See the discussion above in the Compensation Discussion and Analysis under the heading “Actions Taken in 2014 in Light of Proposed Merger.”

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 the 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 our named executive officers during 2014, including equity and nonequity based awards. Decisions regarding equity and nonequity awards (payable following vesting or performance periods) were made only one time during 2014. Equity incentive-based awards are subject to the Compensation – Stock Compensation Topic of the FASB ASC, and performance shares are subject to a market condition thereunder. Nonequity incentive plan awards are not subject to the Compensation – Stock Compensation Topic of the FASB ASC and are intended to serve as an incentive for performance to occur over the given year. For a detailed description of long-term incentive plans (performance shares, restricted stock units, and stock options), see the discussion above in the Compensation Discussion and Analysis under the heading “Key Components of our Executive Compensation Program - Long-Term Incentive Compensation.”

Name	Grant Date	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)]
		Threshold ($)	Target ($)	Superior ($)	Threshold (#)	Target (#)	Superior (#)				
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Charles A. Schrock	2014	0	943,304	1,886,608							
	02/13/14				14,776	29,552	59,104				1,308,563
	02/13/14							8,649			477,684
	02/13/14								73,922	55.23	495,277
James F. Schott	2014	0	264,000	528,000							
	02/13/14				3,584	7,168	14,336				317,399
	02/13/14							2,098			115,873
	02/13/14								17,930	55.23	120,131
Lawrence T. Borgard	2014	0	450,000	900,000							
	02/13/14				7,519	15,038	30,076				665,883
	02/13/14							4,401			243,067
	02/13/14								37,615	55.23	252,021
Phillip M. Mikulsky	2014	0	270,108	540,216							
	02/13/14				3,526	7,052	14,104				312,263
	02/13/14							2,064			113,995
	02/13/14								17,639	55.23	118,181
Mark A. Radtke	2014	0	248,784	497,568							
	02/13/14				3,456	6,911	13,822				306,019
	02/13/14							2,023			111,730
	02/13/14								17,287	55.23	115,823

(1)

Based on the Integrys 2014 Executive Incentive Plan payout percentages. For more information, see the discussion above in the Compensation Discussion and Analysis under the heading “Key Components of our Executive Compensation Program - Short-Term Incentive Compensation.”

(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 “advanced lattice” option pricing model.

As reflected in the table above, the compensation committee awarded restricted stock units to each named executive officer 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 each of the named executive officers. 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. 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 each of the named executive officers. 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 TSR 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 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, for each of our named executive officers as of December 31, 2014:

	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 ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#) [2]	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) [3] [4]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) [3] [4]
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Charles A. Schrock						23,555	1,833,757	59,944	4,666,640
James F. Schott						4,253	331,096	12,986	1,010,960
Lawrence T. Borgard						10,655	829,492	27,638	2,151,618
Phillip M. Mikulsky						5,683	442,422	14,304	1,113,566
Mark A. Radtke						5,568	433,469	14,018	1,091,301

(1) 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. Schrock	2,419	5,007	7,110	9,019
James F. Schott	245	460	1,360	2,188
Lawrence T. Borgard	1,043	2,075	2,948	4,589
Phillip M. Mikulsky	640	1,195	1,696	2,152
Mark A. Radtke	626	1,171	1,662	2,109

(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 2012-2015 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 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. Schrock	45,588	3,549,026	60,784	4,732,034
James F. Schott	8,727	679,397	11,636	905,863
Lawrence T. Borgard	18,900	1,471,365	25,200	1,961,820
Phillip M. Mikulsky	10,878	846,852	14,504	1,129,136
Mark A. Radtke	10,661	829,920	14,214	1,106,560

2014 Performance Share Grant:

Named Executive Officer	Shares at 200% Payout (#)	Market Value ($)	Shares at 200% Payout (#)	Market Value ($)
Charles A. Schrock	59,104	4,601,246	59,104	4,601,246
James F. Schott	14,336	1,116,058	14,336	1,116,058
Lawrence T. Borgard	30,076	2,341,417	30,076	2,341,417
Phillip M. Mikulsky	14,104	1,097,996	14,104	1,097,996
Mark A. Radtke	13,822	1,076,043	13,822	1,076,043

(4) Not included in columns (i) and (j) above are the performance shares pertaining to grants made in 2012 for the performance period of 2012-2014. Based on performance during this period, a payout at 136% was earned on performance shares for the performance period of 2012-2014 based on final TSR results. The number of earned performance shares attributable to each named executive officer as a result of the threshold level being exceeded, along with the corresponding market value of such shares, is as follows:

Named Executive Officer	Earned Shares (#)	Market or Payout Value of Earned Shares ($)
Charles A. Schrock	34,713	2,702,407
James F. Schott	3,186	248,030
Lawrence T. Borgard	14,392	1,120,417
Phillip M. Mikulsky	8,284	644,909
Mark A. Radtke	8,118	631,986

Option Exercises and Stock Vested Table for 2014

The following table sets forth amounts received by each of our named executive officers upon exercise of options (or similar instrument) or the vesting of stock (or similar instruments) during 2014:

	Option Awards		Stock Awards [1]	
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. Schrock	554,924	11,743,848	44,540	3,171,098
James F. Schott	76,484	1,468,048	4,207	297,772
Lawrence T. Borgard	209,780	3,886,395	18,477	1,315,287
Phillip M. Mikulsky	67,937	1,182,585	10,771	764,450
Mark A. Radtke	93,303	1,880,588	10,554	749,065

(1) In December 2014, we paid the named executive officers 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 compensation committee. Because the final 2012-2014 long-term 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.

Pension Benefits Table for 2014

The following table sets forth the actuarial present value of each named executive officer's accumulated benefit under each defined benefit plan, assuming benefits are paid at normal retirement age based on current levels of compensation. For information regarding the valuation method and all material assumptions applied in quantifying the present value of the current accumulated benefit for each of the named executive officers, see Note 18, Employee Benefit Plans in Notes to Consolidated Financial Statements; such information is incorporated herein by reference. The table also shows the number of years of credited service under each such plan, computed as of the same pension plan measurement date used in the company's audited financial statements for the year ended December 31, 2014. James F. Schott, Charles A. Schrock, and Phillip M. Mikulsky are currently eligible for early retirement. No pension benefits were paid during the year to any of the named executive officers who were still employed at the end of 2014. For more information regarding pension benefits, please see the discussion above in the Compensation Discussion and Analysis under the heading "Key Components of our Executive Compensation Program - Other Benefits and Plans."

Name	Plan Name (1)	Number of Years Credited Service (#) (2)	Present Value of Accumulated Benefits ($) (3)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
Charles A. Schrock	Pension Plan	33	1,256,617	0
	Pension Restoration Plan	33	6,741,641	0
	SERP	35	3,735,180	0
	Total	35	11,733,438	0
James F. Schott	Pension Plan	9	232,591	0
	Pension Restoration Plan	9	148,166	0
	Total	9	380,757	0
Lawrence T. Borgard	Pension Plan			