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

FORM 10-Q

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-3016	WISCONSIN PUBLIC SERVICE CORPORATION (A Wisconsin Corporation) 700 North Adams Street P. O. Box 19001 Green Bay, WI 54307-9001 800-450-7260	39-0715160

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

Yes ☒ No ☐

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

Yes ☒ No ☐

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

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

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 ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common stock, \$4 par value,
23,896,962 shares outstanding at
August 5, 2014

WISCONSIN PUBLIC SERVICE CORPORATION
QUARTERLY REPORT ON FORM 10-Q
For the Quarter Ended June 30, 2014
TABLE OF CONTENTS

	<u>Page</u>
<u>Forward-Looking Statements</u>	<u>1</u>
<u>PART I. FINANCIAL INFORMATION</u>	<u>2</u>
<u>ITEM 1. FINANCIAL STATEMENTS (Unaudited)</u>	<u>2</u>
<u>Condensed Consolidated Statements of Income</u>	<u>2</u>
<u>Condensed Consolidated Balance Sheets</u>	<u>3</u>
<u>Condensed Consolidated Statements of Capitalization</u>	<u>4</u>
<u>Condensed Consolidated Statements of Cash Flows</u>	<u>5</u>
<u>Condensed Notes to Financial Statements</u>	<u>6</u>
	<u>Page</u>
<u>Note 1 Basis of Presentation</u>	<u>6</u>
<u>Note 2 Proposed Merger of Parent Company with Wisconsin Energy Corporation</u>	<u>6</u>
<u>Note 3 Acquisition of Fox Energy Center</u>	<u>6</u>
<u>Note 4 Cash and Cash Equivalents</u>	<u>7</u>
<u>Note 5 Risk Management Activities</u>	<u>7</u>
<u>Note 6 Goodwill and Other Intangible Assets</u>	<u>8</u>
<u>Note 7 Short-Term Debt and Lines of Credit</u>	<u>9</u>
<u>Note 8 Income Taxes</u>	<u>9</u>
<u>Note 9 Commitments and Contingencies</u>	<u>10</u>
<u>Note 10 Employee Benefit Plans</u>	<u>12</u>
<u>Note 11 Stock-Based Compensation</u>	<u>13</u>
<u>Note 12 Common Equity</u>	<u>15</u>
<u>Note 13 Fair Value</u>	<u>15</u>
<u>Note 14 Miscellaneous Income</u>	<u>18</u>
<u>Note 15 Regulatory Environment</u>	<u>18</u>
<u>Note 16 Segments of Business</u>	<u>19</u>
<u>Note 17 Related Party Transactions</u>	<u>20</u>
<u>Note 18 New Accounting Pronouncements</u>	<u>21</u>
<u>ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>22</u>
<u>ITEM 3. Quantitative and Qualitative Disclosures About Market Risk</u>	<u>33</u>
<u>ITEM 4. Controls and Procedures</u>	<u>34</u>
<u>PART II. OTHER INFORMATION</u>	<u>35</u>
<u>ITEM 1. Legal Proceedings</u>	<u>35</u>
<u>ITEM 1A. Risk Factors</u>	<u>35</u>
<u>ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	<u>35</u>
<u>ITEM 6. Exhibits</u>	<u>35</u>
<u>Signature</u>	<u>36</u>
<u>EXHIBIT INDEX</u>	<u>37</u>

Acronyms Used in this Quarterly Report on Form 10-Q

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

Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot provide assurance that such statements will prove correct.

Forward-looking statements involve a number of risks and uncertainties. Some risks and uncertainties that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013, as may be amended or supplemented in Part II, Item 1A of our subsequently filed Quarterly Reports on Form 10-Q (including this report), and those identified below:

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

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

WISCONSIN PUBLIC SERVICE CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2014	2013	2014	2013
<i>(Millions)</i>				
Operating revenues	\$ 358.8	\$ 367.8	\$ 914.5	\$ 801.2
Cost of fuel, natural gas, and purchased power	150.8	164.3	456.6	376.9
Operating and maintenance expense	130.6	116.9	252.7	224.2
Depreciation and amortization expense	28.3	27.8	55.9	51.2
Taxes other than income taxes	12.6	11.9	25.2	24.6
Operating income	36.5	46.9	124.1	124.3
Miscellaneous income	6.6	5.9	13.9	10.9
Interest expense	14.3	10.3	28.3	21.2
Other expense	(7.7)	(4.4)	(14.4)	(10.3)
Income before taxes	28.8	42.5	109.7	114.0
Provision for income taxes	10.9	15.8	40.7	41.9
Net income	17.9	26.7	69.0	72.1
Preferred stock dividend requirements	(0.8)	(0.8)	(1.6)	(1.6)
Net income attributed to common shareholder	\$ 17.1	\$ 25.9	\$ 67.4	\$ 70.5

The accompanying condensed notes are an integral part of these statements.

WISCONSIN PUBLIC SERVICE CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (Millions, except share and per share data)	June 30 2014	December 31 2013
Assets		
Cash and cash equivalents	\$ 20.3	\$ 5.7
Accounts receivable and accrued unbilled revenues, net of reserves of \$4.3 and \$2.5, respectively	188.8	209.8
Receivables from related parties	4.5	5.2
Inventories		
Fuel and gas	65.9	60.0
Materials and supplies, at average cost	39.0	34.9
Regulatory assets	32.8	46.2
Prepaid taxes	40.8	63.6
Other current assets	16.4	16.7
Current assets	408.5	442.1
Property, plant, and equipment, net of accumulated depreciation of \$1,526.9 and \$1,483.1, respectively	2,977.6	2,887.7
Regulatory assets	345.3	342.5
Goodwill	36.4	36.4
Pension and other postretirement benefit assets	219.0	145.1
Other long-term assets	109.8	107.5
Total assets	\$ 4,096.6	\$ 3,961.3
Liabilities and Shareholders' Equity		
Short-term debt	\$ 60.4	\$ 25.6
Current portion of long-term debt to parent	2.2	—
Accounts payable	146.9	131.8
Payables to related parties	16.5	13.8
Regulatory liabilities	25.2	38.0
Other current liabilities	68.9	72.0
Current liabilities	320.1	281.2
Long-term debt to parent	3.7	6.3
Long-term debt	1,174.5	1,174.5
Deferred income taxes	655.5	619.5
Deferred investment tax credits	7.9	8.1
Regulatory liabilities	338.3	286.3
Environmental remediation liabilities	70.0	64.4
Pension and other postretirement benefit obligations	33.5	76.4
Payables to related parties	5.7	6.1
Other long-term liabilities	68.1	71.9
Long-term liabilities	2,357.2	2,313.5
Commitments and contingencies		
Preferred stock – \$100 par value; 1,000,000 shares authorized; 511,882 shares issued and outstanding	51.2	51.2
Common stock – \$4 par value; 32,000,000 shares authorized; 23,896,962 shares issued and outstanding	95.6	95.6
Additional paid-in capital	764.9	723.5
Retained earnings	507.6	496.3
Total liabilities and shareholders' equity	\$ 4,096.6	\$ 3,961.3

The accompanying condensed notes are an integral part of these statements.

WISCONSIN PUBLIC SERVICE CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CAPITALIZATION (Unaudited)			June 30	December 31
<i>(Millions, except share and per share data)</i>			2014	2013
Common stock equity				
Common stock – \$4 par value; 32,000,000 shares authorized; 23,896,962 shares outstanding			\$ 95.6	\$ 95.6
Additional paid-in capital			764.9	723.5
Retained earnings			507.6	496.3
Total common stock equity			1,368.1	1,315.4
Preferred stock				
Cumulative; \$100 par value; 1,000,000 shares authorized with no mandatory redemption –				
	Series	Shares Outstanding		
	5.00%	131,916	13.2	13.2
	5.04%	29,983	3.0	3.0
	5.08%	49,983	5.0	5.0
	6.76%	150,000	15.0	15.0
	6.88%	150,000	15.0	15.0
Total preferred stock		511,882	51.2	51.2
Long-term debt to parent				
	Series	Year Due		
	8.76%	2015	2.2	2.4
	7.35%	2016	3.7	3.9
Total			5.9	6.3
Current portion of long-term debt to parent			(2.2)	—
Total long-term debt to parent			3.7	6.3
Long-term debt				
First Mortgage Bonds				
	Series	Year Due		
	7.125%	2023	0.1	0.1
Senior Notes				
	Series	Year Due		
	6.375%	2015	125.0	125.0
	5.65%	2017	125.0	125.0
	6.08%	2028	50.0	50.0
	5.55%	2036	125.0	125.0
	3.671%	2042	300.0	300.0
	4.752%	2044	450.0	450.0
Total First Mortgage Bonds and Senior Notes			1,175.1	1,175.1
Unamortized discount on long-term debt			(0.6)	(0.6)
Total long-term debt			1,174.5	1,174.5
Total capitalization			\$ 2,597.5	\$ 2,547.4

The accompanying condensed notes are an integral part of these statements.

WISCONSIN PUBLIC SERVICE CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)	Six Months Ended	
	June 30	
(Millions)	2014	2013
Operating Activities		
Net income	\$ 69.0	\$ 72.1
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization expense	55.9	51.2
Recoveries and refunds of regulatory assets and liabilities	7.5	(5.2)
Bad debt expense	2.6	1.5
Pension and other postretirement (credit) expense	(2.5)	11.3
Pension and other postretirement contributions	(46.5)	(37.8)
Deferred income taxes and investment tax credits	34.9	51.3
Termination of tolling agreement with Fox Energy Company LLC	—	(50.0)
Deferrals to regulatory assets and liabilities	(19.6)	(2.6)
Other	(9.2)	(1.5)
Changes in working capital		
Accounts receivable and accrued unbilled revenues	18.1	10.3
Inventories	(10.4)	11.1
Prepaid taxes	22.8	(6.6)
Other current assets	3.3	4.5
Accounts payable	8.5	(26.9)
Other current liabilities	(7.5)	9.0
Net cash provided by operating activities	126.9	91.7
Investing Activities		
Capital expenditures	(129.2)	(111.9)
Acquisition of Fox Energy Company LLC	—	(391.6)
Grant received related to Crane Creek wind project	—	69.0
Other	2.3	1.8
Net cash used for investing activities	(126.9)	(432.7)
Financing Activities		
Short-term debt, net	34.8	51.8
Borrowing on term credit facility	—	200.0
Repayment of long-term debt	—	(22.0)
Repayment of long-term debt to parent	(0.4)	(0.4)
Payment of dividends to parent	(55.9)	(54.3)
Equity contribution from parent	40.0	200.0
Return of capital to parent	—	(35.0)
Preferred stock dividend requirements	(1.6)	(1.6)
Other	(2.3)	0.6
Net cash provided by financing activities	14.6	339.1
Net change in cash and cash equivalents	14.6	(1.9)
Cash and cash equivalents at beginning of period	5.7	6.5
Cash and cash equivalents at end of period	\$ 20.3	\$ 4.6
<i>Cash paid for interest</i>	<i>\$ 27.8</i>	<i>\$ 22.1</i>
<i>Cash received for income taxes</i>	<i>\$ (9.2)</i>	<i>\$ (2.0)</i>

The accompanying condensed notes are an integral part of these statements.

WISCONSIN PUBLIC SERVICE CORPORATION AND SUBSIDIARY
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
June 30, 2014

Note 1—Basis of Presentation

As used in these notes, the term "financial statements" refers to the condensed consolidated financial statements. This includes the condensed consolidated statements of income, condensed consolidated balance sheets, condensed consolidated statements of capitalization, and condensed consolidated statements of cash flows, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to WPS.

We prepare our financial statements in conformity with the rules and regulations of the SEC for Quarterly Reports on Form 10-Q and in accordance with GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2013. Financial results for an interim period may not give a true indication of results for the year.

In management's opinion, these unaudited financial statements include all adjustments necessary for a fair presentation of financial results. All adjustments are normal and recurring, unless otherwise noted. All intercompany transactions have been eliminated in consolidation.

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

In June 2014, our parent company, Integrys Energy Group, entered into an Agreement and Plan of Merger with Wisconsin Energy Corporation. This transaction was approved unanimously by the Boards of Directors of both companies. It is subject to various approvals, including the shareholders of both companies, the FERC, Federal Communications Commission, PSCW, and other regulatory commissions. The transaction also is subject to the notification and clearance and reporting requirements under the Hart-Scott-Rodino Act and other customary closing conditions. The transaction is expected to close in the summer of 2015.

Note 3—Acquisition of Fox Energy Center

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

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

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

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

⁽¹⁾ Relates to the electric utility segment.

⁽²⁾ Intangible assets recorded for contractual services agreements. See Note 6, Goodwill and Other Intangible Assets, for more information.

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

We received regulatory approval to defer incremental costs incurred in 2013 associated with the purchase of the facility. These costs are included in our 2015 proposed retail electric rate increase. See Note 15, Regulatory Environment, for more information. Our rate order effective January 1, 2014, included the costs of operating the Fox Energy Center.

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

Note 4—Cash and Cash Equivalents

Short-term investments with an original maturity of three months or less are reported as cash equivalents.

Construction costs funded through accounts payable totaled \$46.3 million at June 30, 2014, and \$25.1 million at June 30, 2013. These costs were treated as noncash investing activities.

Note 5—Risk Management Activities

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

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

(Millions)	Balance Sheet Presentation *	June 30, 2014	
		Assets	Liabilities
Natural gas contracts	Other Current	\$ 0.6	\$ 0.2
FTRs	Other Current	4.7	0.7
Petroleum product contracts	Other Current	0.2	—
Coal contracts	Other Current	—	1.6
Coal contracts	Other Long-term	2.7	0.2
	Other Current	5.5	2.5
	Other Long-term	2.7	0.2
Total		\$ 8.2	\$ 2.7

* We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

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

* We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

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

(Millions)	June 30, 2014		
	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	\$ 5.5	\$ 0.9	\$ 4.6
Derivative assets not subject to master netting or similar arrangements	2.7		2.7
Total risk management assets	\$ 8.2		\$ 7.3
Derivative liabilities subject to master netting or similar arrangements	\$ 0.9	\$ 0.9	\$ —
Derivative liabilities not subject to master netting or similar arrangements	1.8		1.8
Total risk management liabilities	\$ 2.7		\$ 1.8

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

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

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)	June 30, 2014	December 31, 2013
Cash collateral provided to others related to contracts under master netting or similar arrangements *	\$ 3.4	\$ 3.1
Cash collateral received from others related to contracts under master netting or similar arrangements *	—	0.2

* Cash collateral provided to others is reflected in other current assets and cash collateral received from others is reflected in other current liabilities on the balance sheets.

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

(Millions)	Financial Statement Presentation	Three Months Ended June 30		Six Months Ended June 30	
		2014	2013	2014	2013
Natural gas	Balance Sheet — Regulatory assets (current)	\$ (0.3)	\$ (0.5)	\$ (0.1)	\$ 0.5
Natural gas	Balance Sheet — Regulatory liabilities (current)	(0.2)	(0.9)	(0.1)	(0.1)
FTRs	Balance Sheet — Regulatory assets (current)	(1.0)	(1.0)	(0.9)	(0.8)
FTRs	Balance Sheet — Regulatory liabilities (current)	1.1	0.1	1.0	(0.3)
Petroleum	Balance Sheet — Regulatory assets (current)	—	(0.1)	—	(0.1)
Coal	Balance Sheet — Regulatory assets (current)	(0.3)	0.8	(0.1)	2.7
Coal	Balance Sheet — Regulatory assets (long-term)	0.2	1.7	0.6	4.0
Coal	Balance Sheet — Regulatory liabilities (current)	—	(0.1)	—	(0.3)
Coal	Balance Sheet — Regulatory liabilities (long-term)	0.9	—	2.5	(2.2)

We had the following notional volumes of outstanding derivative contracts:

(Millions)	June 30, 2014			December 31, 2013		
	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	1,659.2	—	N/A	2,242.5	7.0	N/A
FTRs (kilowatt-hours)	N/A	N/A	7,891.1	N/A	N/A	3,427.0
Petroleum products (barrels)	0.1	—	N/A	0.1	—	N/A
Coal contract (tons)	4.0	—	N/A	4.8	—	N/A

Note 6—Goodwill and Other Intangible Assets

We had no changes to the carrying amount of goodwill during the six months ended June 30, 2014, and 2013. In the second quarter of 2014, we completed our annual goodwill impairment test, and no impairment resulted from this test.

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

(Millions)	June 30, 2014			December 31, 2013		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Contractual service agreements *	\$ 15.6	\$ (3.0)	\$ 12.6	\$ 15.6	\$ (1.8)	\$ 13.8

* The remaining amortization period for these intangible assets at June 30, 2014, was approximately six years.

The table below shows our amortization expense recognized in the statements of income:

(Millions)	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Amortization recorded in depreciation and amortization expense	\$ 0.6	\$ 0.6	\$ 1.2	\$ 0.6

The following table shows our estimated amortization expense for the next five years, including amounts recorded through June 30, 2014:

(Millions)	For the Year Ending December 31				
	2014	2015	2016	2017	2018
Amortization to be recorded in depreciation and amortization expense	\$ 2.2	\$ 2.2	\$ 2.2	\$ 2.2	\$ 2.2

Note 7—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	June 30, 2014	December 31, 2013
Commercial paper	\$ 60.4	\$ 25.6
Average interest rate on commercial paper	0.21%	0.14%

The commercial paper outstanding at June 30, 2014, had maturity dates ranging from July 1, 2014, through July 7, 2014.

Our average amount of commercial paper borrowings based on daily outstanding balances during the six months ended June 30, 2014, and 2013, was \$18.5 million and \$70.8 million, respectively.

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:

(Millions)	Maturity	June 30, 2014	December 31, 2013
Revolving credit facility ⁽¹⁾	05/17/2014	\$ —	\$ 135.0
Revolving credit facility ⁽²⁾	05/07/2015	135.0	—
Revolving credit facility	06/13/2017	115.0	115.0
Total short-term credit capacity		\$ 250.0	\$ 250.0
Less:			
Commercial paper outstanding		60.4	25.6
Available capacity under existing agreements		\$ 189.6	\$ 224.4

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

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

Note 8—Income Taxes

We calculate our interim period provision for income taxes based on our projected annual effective tax rate as adjusted for certain discrete items.

The table below shows our effective tax rates:

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Effective tax rate	37.8%	37.2%	37.1%	36.8%

Our effective tax rate normally differs from the federal statutory tax rate of 35% due to additional provision for state income tax obligations. No other items had a significant impact on our effective tax rates during the three and six months ended June 30, 2014, and 2013.

During the three and six months ended June 30, 2014, there was not a significant change in our liability for unrecognized tax benefits.

Note 9—Commitments and Contingencies

(a) Unconditional Purchase Obligations and Purchase Order Commitments

We routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. We have obligations to distribute and sell electricity and natural gas to our customers and expect to recover costs related to these obligations in future customer rates. The following table shows our minimum future commitments related to these purchase obligations as of June 30, 2014.

(Millions)	Year Contracts Extend Through	Total Amounts Committed	Payments Due By Period					Later Years
			2014	2015	2016	2017	2018	
Electric utility								
Purchased power	2029	\$ 892.9	\$ 37.8	\$ 49.0	\$ 42.3	\$ 52.8	\$ 55.8	\$ 655.2
Coal supply and transportation	2018	127.9	26.1	42.8	18.5	20.6	19.9	—
Natural gas utility supply and transportation	2024	265.4	22.1	45.1	43.5	43.0	42.5	69.2
Total		\$ 1,286.2	\$ 86.0	\$ 136.9	\$ 104.3	\$ 116.4	\$ 118.2	\$ 724.4

We also had commitments of \$445.8 million in the form of purchase orders issued to various vendors at June 30, 2014, that relate to normal business operations, including construction projects.

(b) Environmental Matters

Air Permitting Violation Claims

Weston and Pulliam Clean Air Act (CAA) Issues:

In November 2009, the EPA issued a Notice of Violation (NOV) to us alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. We reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the U.S. District Court (Court) in March 2013, after a public comment period. The final Consent Decree includes:

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

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain Weston and Pulliam units. We announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. In July 2014, we filed for approval from the PSCW to reclassify the undepreciated book value of the retired units to a regulatory asset in 2015, with recovery of a full return, and for future amortization at current depreciable rates. We believe that we will receive approval of this treatment from the PSCW.

We received approval from the PSCW in our 2014 rate order to recover prudently incurred 2014 costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty. We also believe that prudently incurred costs after 2014 will be recoverable from customers based on past precedent with the PSCW.

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

In May 2010, we received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that we violated the CAA at the Weston and Pulliam plants. We entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA

NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of June 30, 2014. It is unknown whether the Sierra Club will take further action in the future.

Columbia and Edgewater CAA Issues:

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

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,
- beneficial environmental projects, with our portion totaling \$1.3 million, and
- our portion of a civil penalty and legal fees totaling \$0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain of the Columbia and Edgewater units. As of June 30, 2014, no decision had been made on how to address this requirement. Therefore, retirement of the Columbia and Edgewater units mentioned in the Consent Decree was not considered probable.

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

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

Weston Title V Air Permit:

In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, we challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also filed Petitions for Judicial Review and requests for contested case proceedings regarding various aspects of the permit. The WDNR granted all parties' requests for contested case proceedings. We filed permit amendment applications such that, if the facility permits and the Title V air permit are amended in accordance with the applications, several of the issues we raised would be resolved. The contested case petitions have not yet been referred to an Administrative Law Judge. The Petitions for Judicial Review, by all parties, have been stayed pending the resolution of the contested cases.

In May 2014, the WDNR issued an NOV alleging that we failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System (CEMS) certification. We and the WDNR have begun discussing resolution of this matter. We do not expect this matter to have a material impact on our financial statements.

In May 2014, the WDNR issued a Notice of Inquiry (NOI) alleging that we failed to comply with excess emission summary reporting requirements in the 2013 Weston Title V permit. We believe that such requirements are stayed pursuant to state law pending the outcome of the Weston Title V air permit contested case and have filed a motion with the administrative law judge requesting confirmation of the stay. Briefing is in progress, and we anticipate a decision from the administrative law judge by mid-September 2014. We do not expect this matter to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:

The State of Wisconsin's mercury rule requires 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 will be required to reduce mercury emissions from fuel combusted by a minimum of 90%, or meet certain mercury emission limits annually based on gigawatt-hours of electricity produced. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts, but less than 150 megawatts, must reduce their mercury emissions to a level defined by the Best Available Control Technology rule.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. The State of Wisconsin is in the process of revising the state mercury rule to be consistent with the MATS rule. Projects approved and initiated to address the State of Wisconsin mercury rule are expected to ensure compliance with the mercury limits in the MATS rule.

We expect to be in compliance with the State of Wisconsin's mercury rule by the end of 2014. In addition, we are making progress towards compliance with the MATS rule in 2015. We estimated capital costs of approximately \$9 million for our wholly owned plants to achieve the required

reductions for MATS compliance, of which approximately \$3 million has been expended as of June 30, 2014. The capital costs are expected to be recovered in future rates.

Sulfur Dioxide and Nitrogen Oxide:

In July 2011, the EPA issued a final rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including us, challenged in the United States Court of Appeals 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, 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. There are remaining issues before the D.C. Circuit, and there will need to be additional rulemakings before CSAPR is implemented. As a result, it is premature to speculate on what additional controls or other actions, if any, we may be required to implement. We expect to recover any future compliance costs in future rates.

In June 2014, the EPA requested that the D.C. Circuit lift the stay of CSAPR. Further, the EPA asked the D.C. Circuit to change the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets would apply in 2015 and 2016, and Phase 2 emissions budgets would apply to 2017 and beyond. The stay of CSAPR is still in effect, pending the D.C. Circuit's action on the EPA's request. 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), and the EPA has not revised it to reflect the reinstatement of CAIR. Although particulate emissions also contribute to visibility impairment, the WDNR's modeling has shown the impairment to be so insignificant that additional capital expenditures on controls may not be warranted.

Manufactured Gas Plant Remediation

We operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, we are required to undertake remedial action with respect to some of these materials. We are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies.

We are responsible for the environmental remediation of ten sites, of which seven have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. Our balance sheets include liabilities of \$70.0 million that we have estimated and accrued for as of June 30, 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 June 30, 2014, cash expenditures for environmental remediation not yet recovered in rates were \$11.7 million. Our balance sheets include a regulatory asset of \$81.7 million at June 30, 2014, which is net of insurance recoveries, related to the expected recovery through rates of both cash expenditures and estimated future expenditures. Under current PSCW policies, we may not recover carrying costs associated with the cleanup expenditures.

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

Note 10—Employee Benefit Plans

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

(Millions)	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended June 30		Six Months Ended June 30		Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013	2014	2013	2014	2013
Service cost	\$ 1.9	\$ 2.7	\$ 4.3	\$ 5.4	\$ 1.4	\$ 2.6	\$ 3.9	\$ 5.3
Interest cost	8.5	7.5	17.2	15.3	2.2	3.4	6.1	6.7
Expected return on plan assets	(15.8)	(14.2)	(32.0)	(28.6)	(3.4)	(3.7)	(8.0)	(7.4)
Loss on plan settlement	0.4	—	0.4	—	—	—	—	—
Amortization of prior service cost (credit)	0.2	0.9	0.3	1.8	(2.3)	(0.5)	(3.4)	(1.0)
Amortization of net actuarial loss	3.8	6.2	7.5	12.0	0.7	1.9	1.3	3.7
Net periodic benefit cost (credit)	\$ (1.0)	\$ 3.1	\$ (2.3)	\$ 5.9	\$ (1.4)	\$ 3.7	\$ (0.1)	\$ 7.3

Prior service costs (credits), and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are recorded as net regulatory assets or liabilities.

On March 1, 2014, we remeasured the obligations of certain other postretirement benefit plans in which we are both a sponsor and participant. The remeasurement was necessary because we will replace the current retiree medical plans for participants age 65 and older with a Medicare Advantage plan starting in 2015.

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. During the six months ended June 30, 2014, we contributed \$46.4 million to our pension plans and \$0.1 million to our other postretirement benefit plans. We do not expect to contribute any additional amounts to our pension plans during the remainder of 2014. We expect to contribute an additional \$3.0 million to our other postretirement benefit plans during the remainder of 2014, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

Note 11—Stock-Based Compensation

Our employees may be granted awards under Integrys Energy Group's stock-based compensation plans. Compensation cost associated with these awards is allocated to us based on the percentages used for allocation of the award recipients' labor costs.

The following table reflects the stock-based compensation expense and the related deferred income tax benefit recognized in income for the three and six months ended June 30:

(Millions)	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Stock options	\$ 0.2	\$ 0.2	\$ 0.3	\$ 0.3
Performance stock rights	3.6	0.5	3.8	1.3
Restricted share units	1.0	0.8	2.0	1.8
Total stock-based compensation expense	\$ 4.8	\$ 1.5	\$ 6.1	\$ 3.4
Deferred income tax benefit	\$ 1.9	\$ 0.6	\$ 2.4	\$ 1.4

No stock-based compensation cost was capitalized during the three and six months ended June 30, 2014, and 2013.

Stock Options

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

	February 2014 Grant
Expected term	8 years
Risk-free interest rate	0.12% – 2.88%
Expected dividend yield	5.28%
Expected volatility	18%

The weighted-average fair value per stock option granted during the six months ended June 30, 2014, and 2013, was \$6.70 and \$6.03, respectively.

A summary of stock option activity for the six months ended June 30, 2014, and information related to outstanding and exercisable stock options at June 30, 2014, is presented below:

	Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2013	49,993	\$ 53.03		
Granted	13,890	55.23		
Exercised	(11,802)	51.77		
Outstanding at June 30, 2014	52,081	\$ 53.90	8.3	\$ 0.9
Exercisable at June 30, 2014	14,801	\$ 51.67	7.4	\$ 0.3

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 June 30, 2014. This is calculated as the difference between Integrys Energy Group's closing stock price on June 30, 2014, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the six months ended June 30, 2014, and 2013, was not significant.

As of June 30, 2014, future compensation cost expected to be recognized for unvested and outstanding stock options was not significant.

Performance Stock Rights

The fair values of performance stock rights are estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate of Integrys Energy Group's common stock. The expected volatility is estimated using one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at June 30:

	2014
Risk-free interest rate	0.06% – 0.60%
Expected dividend yield	5.28% – 5.33%
Expected volatility	17% – 23%

A summary of the activity for the six months ended June 30, 2014, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value *
Outstanding at December 31, 2013	5,561	\$ 45.16
Granted	1,113	44.28
Adjustment for shares not distributed	(3,347)	41.90
Outstanding at June 30, 2014	3,327	\$ 48.15

* 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 the six months ended June 30, 2014, and 2013, was \$44.28 and \$48.50 per performance stock right, respectively.

A summary of the activity for the six months ended June 30, 2014, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2013	9,222
Granted	4,440
Adjustment for shares not distributed	(379)
Outstanding at June 30, 2014	13,283

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of June 30, 2014, was \$85.48 per performance stock right.

No shares of Integrys Energy Group's common stock were distributed for performance stock rights during the six months ended June 30, 2014, because the performance percentage was below the threshold payout level for those rights that were eligible for distribution. The total intrinsic value of shares distributed during the six months ended June 30, 2013, was not significant.

As of June 30, 2014, \$2.9 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 1.5 years.

Restricted Share Units

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the six months ended June 30, 2014, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2013	67,741	\$ 52.06
Granted	28,725	55.23
Dividend equivalents	1,556	54.45
Vested and released	(28,325)	49.50
Transfers	(499)	55.54
Forfeited	(804)	54.64
Outstanding at June 30, 2014	68,394	\$ 54.45

The weighted-average grant date fair value of restricted share units awarded during the six months ended June 30, 2014, and 2013, was \$55.23 and \$56.05 per unit, respectively.

The total intrinsic value of restricted share unit awards vested and released during the six months ended June 30, 2014, and 2013, was \$1.5 million and \$1.6 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted share units during the six months ended June 30, 2014, and 2013, was not significant.

As of June 30, 2014, \$4.9 million of compensation cost related to unvested and outstanding restricted share units was expected to be recognized over a weighted-average period of 2.3 years.

Note 12—Common Equity

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

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

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

As of June 30, 2014, total restricted net assets were \$1,363.4 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was \$30.3 million at June 30, 2014.

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

Integrys Energy Group may provide equity contributions to us or request a return of capital from us in order to maintain utility common equity levels consistent with those allowed by the PSCW. Wisconsin law prohibits us from making loans to or guaranteeing obligations of Integrys Energy Group or its other subsidiaries. During the six months ended June 30, 2014, we paid common stock dividends of \$55.9 million to Integrys Energy Group and received \$40.0 million of equity contributions from Integrys Energy Group.

Note 13—Fair Value

Fair Value Measurements

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. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

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 methodologies.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

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

We determine fair value using a market-based approach that uses observable market inputs where available, and internally developed inputs only when observable market data is not readily available. For the unobservable inputs, consideration is given to the assumptions that market participants would use in valuing the asset or liability. These factors include not only the credit standing of the counterparties involved, but also the impact of our nonperformance risk on our liabilities.

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

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

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:

(Millions)	June 30, 2014			
	Level 1	Level 2	Level 3	Total
Risk management assets				
Natural gas contracts	\$ 0.6	\$ —	\$ —	\$ 0.6
Financial transmission rights (FTRs)	—	—	4.7	4.7
Petroleum product contracts	0.2	—	—	0.2
Coal contracts	—	—	2.7	2.7
Total	\$ 0.8	\$ —	\$ 7.4	\$ 8.2
Risk management liabilities				
Natural gas contracts	\$ 0.2	\$ —	\$ —	\$ 0.2
FTRs	—	—	0.7	0.7
Coal contracts	—	—	1.8	1.8
Total	\$ 0.2	\$ —	\$ 2.5	\$ 2.7

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

The risk management assets and liabilities listed in the tables above include NYMEX futures and options, financial contracts used to manage transmission congestion costs in the MISO market, and physical commodity contracts. NYMEX contracts are valued using the NYMEX end-of-day settlement price, which is a Level 1 input. The valuation for physical coal contracts is categorized in Level 3 as it is based on significant assumptions made to extrapolate prices from the last quoted period through the end of the transaction term. The valuation for FTRs is derived from historical data from MISO, which is also considered a Level 3 input. See Note 5, Risk Management Activities, for more information

There were no transfers between the levels of the fair value hierarchy during the three or six months ended June 30, 2014, and 2013.

The amounts listed in the table below represent the range of unobservable inputs used in the valuations that individually had a significant impact on the fair value determination and caused a derivative to be classified as Level 3 at June 30, 2014:

	Fair Value (Millions)		Valuation Technique	Unobservable Input	Average or Range
	Assets	Liabilities			
FTRs	\$ 4.7	\$ 0.7	Market-based	Forward market prices (\$/megawatt-month) ⁽¹⁾	\$181.69
Coal contract	2.7	1.8	Market-based	Forward market prices (\$/ton) ⁽²⁾	\$12.49 — \$15.90

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

⁽²⁾ Represents third-party forward market pricing.

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

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

(Millions)	Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
	FTRs	Coal Contracts	Total	FTRs	Coal Contracts	Total
Balance at the beginning of period	\$ 0.5	\$ 0.3	\$ 0.8	\$ 1.2	\$ (2.5)	\$ (1.3)
Net realized gains included in earnings	0.1	—	0.1	0.8	—	0.8
Net unrealized gains recorded as regulatory assets or liabilities	0.1	0.8	0.9	0.1	3.0	3.1
Purchases	4.4	—	4.4	4.3	—	4.3
Settlements	(1.1)	(0.2)	(1.3)	(2.4)	0.4	(2.0)
Balance at the end of period	\$ 4.0	\$ 0.9	\$ 4.9	\$ 4.0	\$ 0.9	\$ 4.9

(Millions)	Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
	FTRs	Coal Contracts	Total	FTRs	Coal Contracts	Total
Balance at the beginning of period	\$ 0.6	\$ (4.6)	\$ (4.0)	\$ 1.1	\$ (6.5)	\$ (5.4)
Net realized gains included in earnings	0.4	—	0.4	1.0	—	1.0
Net unrealized (losses) gains recorded as regulatory assets or liabilities	(0.9)	3.6	2.7	(1.1)	6.7	5.6
Purchases	3.2	—	3.2	3.2	—	3.2
Sales	(0.1)	—	(0.1)	(0.1)	—	(0.1)
Settlements	(1.1)	(1.3)	(2.4)	(2.0)	(2.5)	(4.5)
Balance at the end of period	\$ 2.1	\$ (2.3)	\$ (0.2)	\$ 2.1	\$ (2.3)	\$ (0.2)

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

Fair Value of Financial Instruments

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

(Millions)	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	\$ 1,174.5	\$ 1,248.8	\$ 1,174.5	\$ 1,176.5
Long-term debt to parent	5.9	6.3	6.3	7.1
Preferred stock	51.2	61.0	51.2	61.4

The fair values of long-term debt are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity. The fair values of preferred stock are estimated based on quoted market prices, when available, or by

using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy.

Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, and outstanding commercial paper, the carrying amount for each such item approximates fair value.

Note 14—Miscellaneous Income

Total miscellaneous income was as follows:

<i>(Millions)</i>	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Equity portion of AFUDC	\$ 2.7	\$ 2.1	\$ 6.3	\$ 3.7
Earnings from equity method investments	2.8	2.8	5.6	5.8
Key executive life insurance for retired employees	0.7	0.8	1.4	0.9
Other	0.4	0.2	0.6	0.5
Total miscellaneous income	\$ 6.6	\$ 5.9	\$ 13.9	\$ 10.9

Note 15—Regulatory Environment

Wisconsin

2015 Rate Case

In April 2014, we filed an application with the PSCW to increase retail electric rates \$76.8 million and to decrease natural gas rates \$1.6 million, with rates expected to be effective January 1, 2015. Our request reflects a 10.60% return on common equity and a target common equity ratio of 50.51% in our regulatory capital structure.

The proposed retail electric rate increase is primarily driven by the completion of a partial refund to customers of the 2013 fuel cost over-collections in 2014 rates, which kept rates flat in 2014, as well as a reduction in refunds associated with decoupling. In 2015, fuel and purchased power costs are expected to increase, as are transmission costs and general inflation. The proposed retail electric rate increase also includes our request to recover deferred costs over four years related to the 2013 acquisition of the Fox Energy Center. Finally, capital costs associated with both previously approved environmental upgrades at the Columbia plant as well as our efforts to improve electric reliability by converting historically low performance overhead distribution lines to underground are also contributing to the requested increase in retail electric rates. The requested increase in retail electric rates was partially offset by the remaining 2013 fuel cost over-collections to customers. In July 2014, the PSCW authorized us to refund the remaining 2013 fuel cost over-collections to customers, all in 2014 rates, which differed from the original application to refund them in 2015 and 2016 rates. A final decision by the PSCW on the 2015 rates is expected in December 2014.

The proposed retail natural gas rate decrease is being driven by 2013 decoupling over-collections, which will be refunded to customers in 2015. An increase in non-fuel operating and maintenance costs, including the impact of general inflation, and an increase in return on equity partially offset the effect of the 2013 decoupling over-collections.

In May 2014, we filed our proposed electric and natural gas rate designs with the PSCW. These rate designs include significantly higher fixed charges, which better matches the related fixed costs of providing service. The PSCW will review the new rate design as part of the rate-setting process, with a final decision expected in December 2014.

2014 Rates

In December 2013, the PSCW issued a final written order, effective January 1, 2014. It authorized a net retail electric rate decrease of \$12.8 million and a net retail natural gas rate increase of \$4.0 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.14% in our regulatory capital structure. The retail electric rate impact consisted of a rate increase, including recovery of the difference between the 2012 fuel refund and the 2013 rate increase discussed below, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. The retail natural gas rate impact consisted of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 related to the Pulliam and Weston sites. See Note 9, Commitments and Contingencies, for more information. Additionally, the order required us to terminate our existing decoupling mechanism, beginning January 1, 2014.

2013 Rates

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

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

Note 16—Segments of Business

At June 30, 2014, we reported three segments. We manage our reportable segments separately due to their different operating and regulatory environments. Our principal business segments are our regulated electric utility operations and our regulated natural gas utility operations. Our other segment includes nonutility activities, as well as equity earnings from our investments in WRPC and WPS Investments, LLC, which holds an interest in ATC.

The tables below present information related to our reportable segments:

	Regulated Utilities						
(Millions)	Electric Utility	Natural Gas Utility	Total Utility	Other	Reconciling Eliminations	WPS Consolidated	
Three Months Ended June 30, 2014							
External revenues	\$ 291.4	\$ 67.4	\$ 358.8	\$ —	\$ —	\$ 358.8	
Intersegment revenues	—	2.7	2.7	0.4	(3.1)	—	
Depreciation and amortization expense	24.2	4.1	28.3	0.2	(0.2)	28.3	
Miscellaneous income	2.8	0.1	2.9	3.7	—	6.6	
Interest expense	11.2	2.6	13.8	0.5	—	14.3	
Provision for income taxes	9.7	0.2	9.9	1.0	—	10.9	
Preferred stock dividend requirements	(0.6)	(0.2)	(0.8)	—	—	(0.8)	
Net income attributed to common shareholder	14.9	(0.1)	14.8	2.3	—	17.1	
	Regulated Utilities						
(Millions)	Electric Utility	Natural Gas Utility	Total Utility	Other	Reconciling Eliminations	WPS Consolidated	
Three Months Ended June 30, 2013							
External revenues	\$ 306.4	\$ 61.4	\$ 367.8	\$ —	\$ —	\$ 367.8	
Intersegment revenues	—	2.4	2.4	0.3	(2.7)	—	
Depreciation and amortization expense	23.8	4.0	27.8	0.2	(0.2)	27.8	
Miscellaneous income	2.1	—	2.1	3.8	—	5.9	
Interest expense	7.7	2.2	9.9	0.4	—	10.3	
Provision for income taxes	14.5	0.3	14.8	1.0	—	15.8	
Preferred stock dividend requirements	(0.6)	(0.2)	(0.8)	—	—	(0.8)	
Net income attributed to common shareholder	23.1	0.3	23.4	2.5	—	25.9	
	Regulated Utilities						
(Millions)	Electric Utility	Natural Gas Utility	Total Utility	Other	Reconciling Eliminations	WPS Consolidated	
Six Months Ended June 30, 2014							
External revenues	\$ 612.8	\$ 301.7	\$ 914.5	\$ —	\$ —	\$ 914.5	
Intersegment revenues	—	7.1	7.1	0.7	(7.8)	—	
Depreciation and amortization expense	47.7	8.1	55.8	0.4	(0.3)	55.9	
Miscellaneous income	6.3	0.1	6.4	7.5	—	13.9	
Interest expense	22.1	5.2	27.3	1.0	—	28.3	
Provision for income taxes	25.2	13.5	38.7	2.0	—	40.7	
Preferred stock dividend requirements	(1.3)	(0.3)	(1.6)	—	—	(1.6)	
Net income attributed to common shareholder	42.1	20.6	62.7	4.7	—	67.4	
	Regulated Utilities						
(Millions)	Electric Utility	Natural Gas Utility	Total Utility	Other	Reconciling Eliminations	WPS Consolidated	
Six Months Ended June 30, 2013							
External revenues	\$ 614.3	\$ 186.9	\$ 801.2	\$ —	\$ —	\$ 801.2	
Intersegment revenues	—	4.2	4.2	0.6	(4.8)	—	
Depreciation and amortization expense	43.3	7.9	51.2	0.3	(0.3)	51.2	
Miscellaneous income	3.7	0.1	3.8	7.1	—	10.9	
Interest expense	15.9	4.3	20.2	1.0	—	21.2	
Provision for income taxes	29.1	10.9	40.0	1.9	—	41.9	
Preferred stock dividend requirements	(1.3)	(0.3)	(1.6)	—	—	(1.6)	
Net income attributed to common shareholder	48.8	17.4	66.2	4.3	—	70.5	

Note 17—Related Party Transactions

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

Effective January 1, 2014, after approval by the PSCW and other state commissions, a new affiliated interest agreement (Non-IBS AIA) went into effect and replaced certain prior agreements. It governs the provision and receipt of services by Integrys Energy Group subsidiaries, except that IBS will continue to provide services only under the existing IBS affiliated interest agreement (IBS AIA). Services under the Non-IBS AIA are subject to

various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary are priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary are priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary are priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to IBS are priced at cost.

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

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

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

<i>(Millions)</i>	June 30, 2014	December 31, 2013
Notes payable *		
Integrus Energy Group	\$ 5.9	\$ 6.3
Accounts Payable		
ATC	8.2	10.4
Liability related to income tax allocation		
Integrus Energy Group	6.4	6.7

* WPS Leasing, our consolidated subsidiary, has a note payable to our parent company, Integrus Energy Group. At June 30, 2014, the current portion of the note payable was \$2.2 million.

The following table shows activity associated with related party transactions:

<i>(Millions)</i>	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Electric transactions				
Sales to UPPCO	\$ 5.8	\$ 6.0	\$ 11.2	\$ 11.3
Natural gas transactions				
Sales to IES	0.1	0.1	0.2	0.2
Purchases from IES	0.1	0.2	2.4	0.4
Interest expense ⁽¹⁾				
Integrus Energy Group	0.1	0.1	0.2	0.3
Transactions with equity method investees				
Charges from ATC for network transmission services	24.8	24.6	49.5	49.2
Charges to ATC for services and construction	2.7	2.3	5.1	4.1
Purchases of energy from WRPC	1.1	1.0	2.1	2.0
Charges to WRPC for operations	0.3	0.3	0.7	0.5
Equity earnings from WPS Investments, LLC ⁽²⁾	2.6	2.6	5.1	5.1

⁽¹⁾ WPS Leasing, our consolidated subsidiary, has a note payable to our parent company, Integrus Energy Group.

⁽²⁾ WPS Investments, LLC is a consolidated subsidiary of Integrus Energy Group that is jointly owned by Integrus Energy Group, UPPCO, and us. At June 30, 2014, we had an 11.12% interest in WPS Investments accounted for under the equity method. Our ownership percentage has continued to decrease as additional equity contributions are made by Integrus Energy Group to WPS Investments.

Note 18—New Accounting Pronouncements

Recently Issued Accounting Guidance Not Yet Effective

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, "Revenue from Contracts with Customers." This ASU supersedes the revenue recognition requirements in Topic 605 of the FASB's Accounting Standards Codification and most industry-specific guidance throughout the Codification. 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.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2013.

SUMMARY

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

RESULTS OF OPERATIONS

Earnings Summary

(Millions)	Three Months Ended June 30		Change in 2014 Over 2013	Six Months Ended June 30		Change in 2014 Over 2013
	2014	2013		2014	2013	
Electric utility operations	\$ 14.9	\$ 23.1	(35.5)%	\$ 42.1	\$ 48.8	(13.7)%
Natural gas utility operations	(0.1)	0.3	N/A	20.6	17.4	18.4 %
Other operations	2.3	2.5	(8.0)%	4.7	4.3	9.3 %
Net income attributed to common shareholder	\$ 17.1	\$ 25.9	(34.0)%	\$ 67.4	\$ 70.5	(4.4)%

Second Quarter 2014 Compared with Second Quarter 2013

The \$8.8 million decrease in our earnings was driven by:

- A \$9.0 million after-tax increase in electric and natural gas utility operating expenses, driven by an increase in maintenance expense. The increase was primarily due to planned major outages at the Fox Energy Center and Weston 4 plant in 2014.
- A \$2.9 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.
- A \$3.6 million after-tax decrease in electric utility margins due to variances in retail sales volumes, net of decoupling. Our decoupling mechanism was terminated effective January 1, 2014.

Partially offsetting these decreases was a \$5.1 million after-tax increase in margins related to our 2014 PSCW electric rate order effective January 1, 2014.

Six Months 2014 Compared with Six Months 2013

The \$3.1 million decrease in our earnings was driven by:

- A \$20.4 million after-tax increase in electric and natural gas utility operating expenses. The increase was driven by higher maintenance expense, primarily due to planned major outages at the Fox Energy Center and Weston 4 plant. Other operating costs associated with the Fox Energy Center also contributed to the increase. We acquired the Fox Energy Center at the end of the first quarter of 2013, and the costs associated with it are being recovered through the rate order mentioned below.
- A \$5.4 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.

These decreases were partially offset by:

- A \$13.4 million after-tax increase in margins related to our 2014 PSCW electric rate order effective January 1, 2014.
- An \$8.3 million after-tax increase in natural gas utility margins due to variances in sales volumes, net of decoupling. The increase was driven by colder than normal weather in 2014 as our decoupling mechanism was terminated effective January 1, 2014.

Electric Utility Segment Operations

<i>(Millions, except degree days)</i>	Three Months Ended June 30		Change in 2014 Over 2013	Six Months Ended June 30		Change in 2014 Over 2013
	2014	2013		2014	2013	
Revenues	\$ 291.4	\$ 306.4	(4.9)%	\$ 612.8	\$ 614.3	(0.2)%
Fuel and purchased power costs	109.8	127.7	(14.0)%	240.4	265.9	(9.6)%
Margins	181.6	178.7	1.6 %	372.4	348.4	6.9 %
Operating and maintenance expense	112.5	100.4	12.1 %	217.7	191.6	13.6 %
Depreciation and amortization expense	24.2	23.8	1.7 %	47.7	43.3	10.2 %
Taxes other than income taxes	11.3	10.7	5.6 %	22.6	22.1	2.3 %
Operating income	33.6	43.8	(23.3)%	84.4	91.4	(7.7)%
Miscellaneous income	2.8	2.1	33.3 %	6.3	3.7	70.3 %
Interest expense	11.2	7.7	45.5 %	22.1	15.9	39.0 %
Other expense	(8.4)	(5.6)	50.0 %	(15.8)	(12.2)	29.5 %
Income before taxes	\$ 25.2	\$ 38.2	(34.0)%	\$ 68.6	\$ 79.2	(13.4)%
Sales in kilowatt-hours						
Residential	627.5	631.7	(0.7)%	1,446.3	1,382.5	4.6 %
Commercial and industrial	1,969.6	1,958.0	0.6 %	3,926.2	3,883.2	1.1 %
Wholesale	821.3	1,245.8	(34.1)%	1,601.0	2,391.8	(33.1)%
Other	6.4	6.8	(5.9)%	15.8	15.9	(0.6)%
Total sales in kilowatt-hours	3,424.8	3,842.3	(10.9)%	6,989.3	7,673.4	(8.9)%
Weather						
Actual heating degree days	1,020	1,107	(7.9)%	5,535	4,910	12.7 %
Normal heating degree days	975	978	(0.3)%	4,621	4,621	— %
Actual cooling degree days	109	131	(16.8)%	109	131	(16.8)%
Normal cooling degree days	141	137	2.9 %	141	137	2.9 %

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

Second Quarter 2014 Compared with Second Quarter 2013**Margins**

Electric utility segment margins increased \$2.9 million.

- Margins increased approximately \$8 million related to our PSCW rate order, effective January 1, 2014. See Note 15, Regulatory Environment, for more information.
 - Excluding the impacts from fuel and purchased power costs, our PSCW rate order resulted in an approximate \$20 million increase in margins. The increase was driven by the costs to operate the Fox Energy Center, which were included in rates beginning in 2014. Although the PSCW approved an electric rate decrease, the rate decrease was driven by 2013 fuel cost over-collections and 2012 decoupling over-collections that are being refunded to customers in 2014 and have no impact on margins.
 - Partially offsetting this increase was an approximate \$12 million decrease in margins related to fuel and purchased power costs. The decrease was driven by approximately \$8 million of fuel and purchased power costs that are not included in the fuel rule recovery mechanism. In 2013, purchased power costs were lower than rate-case approved amounts as a result of the acquisition of Fox Energy Company LLC. Margins were further decreased by approximately \$4 million related to fuel and purchased power cost under-collections in 2014, compared with over-collections in 2013. Under the fuel rule, we can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.
- Margins decreased approximately \$6 million related to sales volume variances, net of the impact of decoupling. The decrease was primarily driven by the termination of our decoupling mechanism, effective January 1, 2014. See Note 15, Regulatory Environment, for more information. Margins from our large commercial and industrial customers also decreased, driven by lower use per customer in the second quarter of 2014. Our decoupling mechanism did not cover large commercial and industrial customers.

Operating Income

Operating income at the regulated electric utility segment decreased \$10.2 million. The decrease was driven by a \$13.1 million increase in operating expenses, partially offset by the \$2.9 million increase in margins discussed above.

The increase in operating expenses was driven by:

- A \$12.5 million increase in maintenance expense, primarily due to planned major outages at the Fox Energy Center and Weston 4 plant in 2014, as well as maintenance at certain other generation plants.
- A \$1.4 million net increase in electric transmission expense. Increases in electric transmission expense of \$2.9 million were partially offset by deferrals approved by the PSCW of \$1.5 million related to system support resource costs for retail customers. See Other Future Considerations, Presque Isle System Support Resources (SSR) Costs, for more information.
- Amortization expense of \$1.4 million for a regulatory asset related to the fee paid for the early termination of the power purchase agreement in connection with the Fox Energy Center acquisition. Margins increased by an equal amount, resulting in no impact on earnings.
- A \$0.7 million net increase in employee benefit costs. The increase in employee benefit costs was driven by:
 - The quarter-over-quarter impact of the deferral of employee benefit costs in 2013 and the related amortization in 2014, which together increased employee benefit costs \$3.6 million. In 2013, we deferred certain increases in pension and other employee benefit costs as a result of our 2013 rate order with the PSCW. We began amortizing this regulatory asset in 2014.
 - Higher stock-based compensation expense of \$2.6 million, which was driven by an increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in Integrys Energy Group's stock price.
 - Other employee benefit costs decreased \$5.5 million in the first quarter of 2014. This decrease was partially driven by a remeasurement of certain other postretirement benefit plans. See Note 10, Employee Benefit Plans, for more information. Higher discount rates assumed in 2014 also contributed to the overall decrease in employee benefit costs.

These increases were partially offset by a \$4.9 million decrease in operating expense due to the quarter-over-quarter impact of the 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, we did receive PSCW approval to defer ownership costs above or below our power purchase agreement expenses in 2013.

Other Expense

Other expense increased \$2.8 million. The primary driver was a \$4.3 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during the second quarter of 2014. An increase in AFUDC of \$0.9 million partially offset the increase in interest expense, largely due to environmental compliance projects at the Columbia plant.

Six Months 2014 Compared with Six Months 2013Margins

Electric utility segment margins increased \$24.0 million, driven by:

- An approximate \$22 million increase in margins related to our PSCW rate order, effective January 1, 2014. See Note 15, Regulatory Environment, for more information.
 - Excluding the impacts from fuel and purchased power costs, the PSCW rate order resulted in an approximate \$36 million increase in margins. The increase was driven by the costs to operate the Fox Energy Center, which were included in rates beginning in 2014. Although the PSCW approved an electric rate decrease, the rate decrease was driven by 2013 fuel cost over-collections and 2012 decoupling over-collections that are being refunded to customers in 2014 and have no impact on margins.
 - Partially offsetting this increase was an approximate \$14 million decrease in margins related to fuel and purchased power costs. The decrease was partially driven by approximately \$7 million of fuel and purchased power costs that are not included in the fuel rule recovery mechanism. In 2013, purchased power costs were lower than rate-case approved amounts as a result of the acquisition of Fox Energy Company LLC. Margins were further decreased by approximately \$7 million related to fuel and purchased power cost under-collections in 2014, compared with over-collections in 2013. Under the fuel rule, we can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

- An approximate \$4 million increase in wholesale margins driven by higher prices. Wholesale prices increased primarily due to the pass-through of increased generation costs to these customers.
- A partially offsetting decrease in margins of approximately \$3 million related to sales volume variances, net of the impact of decoupling. The decrease was primarily driven by the termination of our decoupling mechanism, effective January 1, 2014. See Note 15, Regulatory Environment, for more information. Margins from our large commercial and industrial customers also decreased, driven by lower use per customer in 2014. Our decoupling mechanism did not cover large commercial and industrial customers. These decreases were partially offset by the positive impact that colder than normal weather in 2014 had on margins at the electric utility.

Operating Income

Operating income at the regulated electric utility segment decreased \$7.0 million. The decrease was driven by a \$31.0 million increase in operating expenses, partially offset by the \$24.0 million increase in margins discussed above.

The increase in operating expenses was driven by:

- A \$22.1 million increase in maintenance expense, primarily due to planned major outages at the Pulliam plant, Fox Energy Center, and Weston 4 plant in 2014, as well as maintenance at certain other WPS generation plants.
- 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.
- A \$3.8 million increase in various costs associated with the acquisition and operation of the Fox Energy Center. Included in this amount is the amortization of the regulatory asset related to the fee paid for the early termination of the power purchase agreement in connection with the acquisition. Recovery of the amortization was included in the new rates.
- A \$3.6 million net increase in electric transmission expense. Increases in electric transmission expense of \$6.6 million were partially offset by deferrals approved by the PSCW of \$3.0 million related to system support resource costs for retail customers. See Other Future Considerations, Presque Isle System Support Resources (SSR) Costs, for more information.

These increases were partially offset by:

- A \$3.3 million decrease due to the period-over-period impact of the 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, we did receive PSCW approval to defer ownership costs above or below our power purchase agreement expenses in 2013.
- A \$2.0 million net decrease in employee benefit costs. Employee benefit costs other than stock-based compensation (discussed below) decreased \$11.4 million in 2014. This decrease was partially driven by a remeasurement of certain other postretirement benefit plans. See Note 10, Employee Benefit Plans, for more information. Higher discount rates assumed in 2014 also contributed to the overall decrease in employee benefit costs. This decrease was partially offset by:
 - Higher stock-based compensation expense of \$2.1 million, which was driven by an increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in Integrys Energy Group's stock price.
 - The period-over-period impact of a deferral of employee benefit costs in 2013 and the related amortization in 2014, which together increased employee benefit costs by \$7.3 million. In 2013, we deferred certain increases in pension and other employee benefit costs as a result of our 2013 rate order with the PSCW. We began amortizing this regulatory asset in 2014.

Other Expense

Other expense increased \$3.6 million. The primary driver was a \$7.9 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014. An increase in AFUDC of \$3.7 million partially offset the increase in interest expense, largely due to the installation of the ReACT™ emission control technology at the Weston 3 plant and environmental compliance projects at the Columbia plant.

Natural Gas Utility Segment Operations

<i>(Millions, except degree days)</i>	Three Months Ended June 30		Change in 2014 Over 2013	Six Months Ended June 30		Change in 2014 Over 2013
	2014	2013		2014	2013	
Revenues	\$ 70.1	\$ 63.8	9.9 %	\$ 308.8	\$ 191.1	61.6 %
Natural gas purchased for resale	43.9	39.3	11.7 %	223.7	115.7	93.3 %
Margins	26.2	24.5	6.9 %	85.1	75.4	12.9 %
Operating and maintenance expense	18.0	16.3	10.4 %	34.9	32.2	8.4 %
Depreciation and amortization expense	4.1	4.0	2.5 %	8.1	7.9	2.5 %
Taxes other than income taxes	1.3	1.2	8.3 %	2.6	2.5	4.0 %
Operating income	2.8	3.0	(6.7)%	39.5	32.8	20.4 %
Miscellaneous income	0.1	—	N/A	0.1	0.1	— %
Interest expense	2.6	2.2	18.2 %	5.2	4.3	20.9 %
Other expense	(2.5)	(2.2)	13.6 %	(5.1)	(4.2)	21.4 %
Income before taxes	\$ 0.3	\$ 0.8	(62.5)%	\$ 34.4	\$ 28.6	20.3 %
Retail throughput in therms						
Residential	39.9	40.9	(2.4)%	181.8	159.3	14.1 %
Commercial and industrial	24.9	24.6	1.2 %	112.1	91.6	22.4 %
Other	4.7	5.5	(14.5)%	14.6	11.2	30.4 %
Total retail throughput in therms	69.5	71.0	(2.1)%	308.5	262.1	17.7 %
Transport throughput in therms						
Commercial and industrial	79.8	80.1	(0.4)%	200.6	192.5	4.2 %
Total throughput in therms	149.3	151.1	(1.2)%	509.1	454.6	12.0 %
Weather						
Actual heating degree days	1,020	1,107	(7.9)%	5,535	4,910	12.7 %
Normal heating degree days	975	978	(0.3)%	4,621	4,621	— %

Natural gas utility margins are defined as natural gas utility operating revenues less the cost of natural gas purchased for resale. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 14% and 64% increase in the average per-unit cost of natural gas sold during the three and six months ended June 30, 2014, respectively, which had no impact on margins.

Second Quarter 2014 Compared with Second Quarter 2013Margins

Natural gas utility segment margins increased \$1.7 million, driven by the approximate \$2 million combined effect of the change in weather quarter over quarter, the impact of higher weather-normalized volumes, and the impact of our decoupling mechanism. In 2014, our margins were positively impacted by colder than normal weather as we no longer had a decoupling mechanism in place, effective January 1, 2014. Higher use per customer and an increase in customers also contributed to the increase in margins in 2014.

Operating Income

Operating income at the natural gas utility segment decreased \$0.2 million. This decrease was driven by a \$1.9 million increase in operating expenses, partially offset by the \$1.7 million increase in margins discussed above.

The increase in operating expenses was driven by:

- A \$0.6 million increase in natural gas distribution costs, partially due to increased labor costs related to wage increases and increased meter maintenance.
- A \$0.3 million increase in employee benefit costs driven by:
 - The \$1.1 million negative quarter-over-quarter impact of the deferral of employee benefit costs in 2013 and the related

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

- A \$0.7 million increase in stock-based compensation expense, due to the quarter-over-quarter increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in Integrys Energy Group's stock price.
- These increases were partially offset by a \$1.5 million decrease in other employee benefit costs, driven in part by the remeasurement of certain postretirement benefit plans in the first quarter of 2014. See Note 10, Employee Benefit Plans, for more information. Higher discount rates assumed in 2014 also contributed to the decrease.

There were no other individually significant items that impacted operating expenses.

Six Months 2014 Compared with Six Months 2013

Margins

Natural gas utility segment margins increased \$9.7 million.

- The combined effect of the change in weather period over period, the impact of higher weather-normalized volumes, and the impact of our decoupling mechanism increased margins approximately \$14 million. In 2014, our margins were positively impacted by colder than normal weather as we no longer had a decoupling mechanism in place, effective January 1, 2014. Higher use per customer and an increase in customers also contributed to the increase in margins in 2014.
- Margins were negatively impacted by approximately \$3 million related to our rate order, effective January 1, 2014. The decrease in margins was driven by a natural gas rate decrease and rate design changes in 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 15, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment increased \$6.7 million. This increase was primarily driven by the \$9.7 million increase in margins discussed above, partially offset by a \$3.0 million increase in operating expenses.

The increase in operating expenses was driven by a \$1.4 million increase in natural gas distribution costs, partially due to increased labor costs related to wage increases and increased meter maintenance.

This increase was partially offset by a \$0.2 million decrease in employee benefit costs driven by:

- A \$2.9 million decrease in pension and other postretirement costs, driven in part by the remeasurement of certain postretirement benefit plans in the first quarter of 2014. See Note 10, Employee Benefit Plans, for more information. Higher discount rates assumed in 2014 also contributed to the decrease.
- This decrease was partially offset by the \$2.1 million negative period-over-period impact of the deferral of employee benefit costs in 2013 and the related amortization in 2014. In 2013, we deferred certain increases in pension and other employee benefit costs as a result of our 2013 rate order with the PSCW. We began amortizing this regulatory asset in 2014.

There were no other individually significant items that impacted operating expenses.

Other Segment Operations

(Millions)	Three Months Ended June 30		Change in 2014 Over 2013	Six Months Ended June 30		Change in 2014 Over 2013
	2014	2013		2014	2013	
Operating income	\$ 0.1	\$ 0.1	— %	\$ 0.2	\$ 0.1	100.0%
Other income	3.2	3.4	(5.9)%	6.5	6.1	6.6%
Income before taxes	\$ 3.3	\$ 3.5	(5.7)%	\$ 6.7	\$ 6.2	8.1%

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

Provision for Income Taxes

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Effective tax rate	37.8%	37.2%	37.1%	36.8%

There was no material change in our effective tax rate for all periods presented.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

During the six months ended June 30, 2014, net cash provided by operating activities was \$126.9 million, compared with \$91.7 million during the same period in 2013. The \$35.2 million increase in net cash provided by operating activities was driven by:

- A \$97.8 million increase in cash collections from customers, mainly due to rate increases, higher commodity prices, and the colder than normal weather in 2014. This variance includes the impact of \$12.4 million of natural gas cost over-collections from customers in 2013.
- The positive period-over-period impact of a \$50.0 million payment in 2013 for the early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.
- A \$7.2 million increase in cash received from income taxes, primarily driven by a federal income tax refund received in the first quarter of 2014 for an amended return. Quarterly income tax estimate payments and a federal income tax extension payment made in 2014 partially offset the tax refund received.

These increases in cash were partially offset by:

- A \$78.0 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 than normal weather. To meet the higher energy needs of customers, we purchased fuel and purchased power at higher prices than expected in 2014, which were not yet reflected in the rates charged to our electric customers. This resulted in a period-over-period variance in under-collection from electric utility customers of \$12.5 million. These under-collections were higher in 2014 than in 2013.
- A \$12.6 million decrease in cash related to increased operating and maintenance costs in 2014. The decrease was driven by increases in electric utility maintenance and operating costs associated with the Fox Energy Center, which we acquired at the end of the first quarter of 2013.
- An \$8.4 million decrease in cash from various deferrals, primarily for system support resource costs, pre-certification 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.
- An \$8.7 million increase in contributions to pension and other postretirement benefit plans.
- A \$5.7 million increase in cash paid for interest, primarily driven by an increase in long-term debt in 2014 as compared with 2013.
- A \$5.7 million decrease in cash from customer prepayments and credit balances due to higher natural gas prices and higher sales volumes in 2014. During 2014, customers used more energy than they paid for under budget billing programs.

Investing Cash Flows

During the six months ended June 30, 2014, net cash used for investing activities was \$126.9 million, compared with \$432.7 million during the same period in 2013. The \$305.8 million decrease in net cash used for investing activities was primarily due to \$391.6 million of cash used in 2013 to purchase Fox Energy Company LLC. See Note 3, Acquisition of Fox Energy Center, for more information regarding this purchase. Partially offsetting the decrease in net cash used was the period-over-period negative impact of the receipt of a \$69.0 million Section 1603 Grant for the Crane Creek wind project in 2013 and a \$17.3 million increase in cash used for other capital expenditures (discussed below).

Capital Expenditures

Capital expenditures by business segment for the six months ended June 30 were as follows:

Reportable Segment (millions)	2014	2013	Change in 2014 Over 2013
Electric utility	\$ 111.0	\$ 489.4	\$ (378.4)
Natural gas utility	18.2	14.1	4.1
WPS consolidated	<u>\$ 129.2</u>	<u>\$ 503.5</u>	<u>\$ (374.3)</u>

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

Financing Cash Flows

During the six months ended June 30, 2014, net cash provided by financing activities was \$14.6 million, compared with \$339.1 million for the same period in 2013. The \$324.5 million decrease in net cash provided by financing activities was driven by:

- A \$200.0 million decrease in borrowings under our term credit facility, which were used in 2013 to partially finance the acquisition of Fox Energy Company LLC.
- A \$160.0 million decrease in equity contributions from Integrys Energy Group, which were used to support the acquisition of Fox Energy Company LLC in 2013.
- A \$17.0 million decrease in net borrowings of commercial paper in 2014.

These decreases in cash were partially offset by the period-over-period impact of:

- A \$35.0 million return of capital to parent in 2013.
- A \$22.0 million repayment of long-term debt in 2013.

Significant Financing Activities

For information on short-term debt, see Note 7, Short-Term Debt and Lines of Credit.

There were no significant changes in long-term debt during 2014.

Credit Ratings

Our current credit ratings are listed in the table below:

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

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

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

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of June 30, 2014, including those of our subsidiary:

(Millions)	Total Amounts Committed	Payments Due By Period			
		2014	2015 to 2016	2017 to 2018	2019 and Later Years
Long-term debt principal and interest payments ⁽¹⁾	\$ 2,370.9	\$ 28.7	\$ 231.2	\$ 215.7	\$ 1,895.3
Operating lease obligations	15.7	0.3	1.1	1.1	13.2
Energy and transportation purchase obligations ⁽²⁾	1,286.2	86.0	241.2	234.6	724.4
Purchase orders ⁽³⁾	445.8	340.3	93.3	12.2	—
Pension and other postretirement funding obligations ⁽⁴⁾	5.5	3.0	2.5	—	—
Total contractual cash obligations	\$ 4,124.1	\$ 458.3	\$ 569.3	\$ 463.6	\$ 2,632.9

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

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

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

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

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of \$70.0 million at June 30, 2014, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 9, Commitments and Contingencies, for more information about environmental liabilities.

Capital Requirements

Projected capital expenditures by segment for 2014 through 2016, including amounts expended through June 30, 2014, are as follows:

(Millions)	2014	2015	2016	Total
Electric Utility				
Distribution, transmission and energy supply operations projects	\$ 133	\$ 137	\$ 131	\$ 401
Environmental Projects *	150	135	105	390
Other projects	7	11	158	176
Natural Gas Utility				
Distribution projects	36	30	37	103
Other projects	1	1	1	3
Total capital expenditures	\$ 327	\$ 314	\$ 432	\$ 1,073

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

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, 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 2014 through 2016 primarily through internally generated funds (net of forecasted dividend payments), debt financings, and equity infusions from Integrys Energy Group. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

We currently have two shelf registration statements. Under these registration statements, we may issue up to \$50.0 million of additional senior debt securities and up to \$30.0 million of preferred stock. Amounts, prices, and terms will be determined at the time of future offerings.

At June 30, 2014, we were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future.

Other Future Considerations

Presque Isle System Support Resources (SSR) Costs

In August 2013, Wisconsin Electric Power Company (Wisconsin Electric Power) submitted to MISO a notice, in which Wisconsin Electric Power stated 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 completed its reliability analysis and notified Wisconsin Electric Power in October 2013 that the Presque Isle facilities are required for reliability and would be SSR-designated until alternatives could be implemented to mitigate reliability issues. The SSR Tariff provisions permit MISO to negotiate compensation for generation resources where a market participant desires to retire or suspend operation of the facility but MISO determines that it is needed to maintain system reliability. In exchange for keeping the units in service, MISO will compensate Wisconsin Electric Power by allocating the SSR costs associated with the operation of the Presque Isle units to regulated and nonregulated load serving entities, including us, based on load ratio share within the ATC footprint. In January 2014, MISO submitted a new rate schedule to the FERC reflecting this. Currently, our allocated SSR costs are estimated at \$9 million annually. However, in late July 2014, the FERC granted a complaint filed by the PSCW requesting to change the allocation methodology to the various parties based on a new load-shed analysis to be completed by MISO. The revised methodology will likely result in increased SSR costs.

In April 2013, the PSCW ordered that SSR costs for our retail customers should be deferred until December 31, 2015. At that time, the PSCW will determine the appropriate ratemaking treatment. As of June 30, 2014, \$3.0 million of SSR costs have been deferred for future recovery. SSR costs for our Michigan customers are being recovered through the Power Supply Cost Recovery mechanism. SSR costs for our wholesale customers are being recovered through formula rates.

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 June 2014, the FERC issued a decision, 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%. In this decision, 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 return on equity and capital structure could result in lower equity income and dividends from ATC in the future. We are currently unable to determine the timing and nature of any FERC actions related to this complaint.

Wisconsin Fuel Rule Under-collection "Cap"

We use a "fuel window" mechanism to recover fuel and purchased power costs for our Wisconsin retail electric operations. Under the fuel window rule, actual fuel and purchased power costs that exceed a 2% variance from costs included in the rates charged to customers are deferred for recovery or refund. However, if the deferral of costs in a given year would cause us to earn a greater return on common equity than authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount the return exceeds the authorized amount by the PSCW. This is a possibility in any given year, and at this time, it is unknown whether this provision of the fuel rule will impact us in the current year.

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. The proposed limit may prevent the construction of new coal units until technology becomes commercially available.

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 a timely manner. 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 the 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 nation-wide emission reduction of about 30% from 2005 levels. The EPA intends to issue final rules by June 1, 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 multi-state approach. Facility compliance deadlines will be included in the final state plans.

A risk exists that any greenhouse gas legislation or regulation will increase the cost of producing energy using fossil fuels. However, we believe that capital expenditures being made at our plants are appropriate under any reasonable mandatory greenhouse gas program. We also believe that our

future expenditures that may be required to control greenhouse gas emissions or meet renewable portfolio standards will be recoverable in rates. We will continue to monitor and manage potential risks and opportunities associated with future greenhouse gas legislative or regulatory actions.

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

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

The Dodd-Frank Act was signed into law in July 2010. The final Commodity Futures Trading Commission (CFTC) rulemakings, 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. Some of the rules have not been finalized yet, are being challenged in court, 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 predict how the CFTC's final Dodd-Frank Act rules will ultimately affect us. Certain provisions of the Dodd-Frank Act relating to derivatives could significantly increase our regulatory costs and/or collateral requirements, including our derivatives, which we use to hedge our commercial risks.

We continue to monitor developments related to the Dodd-Frank Act rulemakings and their potential impacts on our future financial results and have implemented the applicable requirements of the Dodd-Frank Act rules that have taken effect. For example, we have addressed certain requirements applicable to transaction reporting and have implemented an internal governance structure. We have also taken the necessary steps to qualify as an end user, which provides for an exemption related to mandatory clearing. Lastly, we have made the necessary systems and process changes to comply with the rules within the CFTC's implementation timelines.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies and considered whether any new critical accounting estimates or other significant changes to our accounting policies require any additional disclosures. We have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2013, are still current and that there have been no significant changes.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Our market risks have not changed materially from the market risks reported in our 2013 Annual Report on Form 10-K.

Item 4. 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 June 30, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

See Note 9, Commitments and Contingencies, for more information on material legal proceedings and matters related to us and our subsidiary.

Item 1A. Risk Factors

There were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2013 Annual Report on Form 10-K, which was filed with the SEC on February 28, 2014.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Dividend Restrictions

Integrus Energy Group is the sole holder of our common stock; therefore, there is no established public trading market for our common stock. See Note 12, Common Equity, for more information on dividends paid and dividend restrictions.

Item 6. Exhibits

The documents listed in the Exhibit Index are attached as exhibits or incorporated by reference herein.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant, Wisconsin Public Service Corporation, has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WISCONSIN PUBLIC SERVICE CORPORATION
(Registrant)

Date: August 6, 2014

/s/ Linda M. Kallas

Linda M. Kallas

Vice President and Controller

(Duly Authorized Officer and Chief Accounting Officer)

WISCONSIN PUBLIC SERVICE CORPORATION
EXHIBIT INDEX TO FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2014

Exhibit No.	Description
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Wisconsin Public Service Corporation
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Wisconsin Public Service Corporation
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Wisconsin Public Service Corporation
101	Financial statements from the Quarterly Report on Form 10-Q of Wisconsin Public Service Corporation for the quarter ended June 30, 2014, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Balance Sheets, (iii) the Condensed Consolidated Statements of Capitalization, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity information