INTEGRYS ENERGY GROUP, INC.
Form 10-Q
November 06, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

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

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

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

Yes [X] No [ ]

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

Yes [X] No [ ]

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

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

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

Yes [ ]   No [X]

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

Common stock, $1 par value,
79,963,091 shares outstanding at
November 4, 2014

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INTEGRYS ENERGY GROUP, INC.
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Acronyms Used in this Quarterly Report on Form 10-Q

AFUDC	Allowance for Funds Used During Construction
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
IES	Integrys Energy Services, Inc.
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC (doing business as Trillium CNG)
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
N/A	Not Applicable
NSG	North Shore Gas Company
PELLC	Peoples Energy, LLC (formerly known as Peoples Energy Corporation)
PGL	The Peoples Gas Light and Coke Company
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WDNR	Wisconsin Department of Natural Resources
WPS	Wisconsin Public Service Corporation

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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 the regulated businesses;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- The possibility that the proposed merger with Wisconsin Energy Corporation (Wisconsin Energy) does not close (including, but not limited to, due to the failure to satisfy the closing conditions), disruption from the proposed merger making it more difficult to maintain our business and operational relationships, and the risk that unexpected costs will be incurred during this process;
- The risk of terrorism or cyber security attacks, including the associated costs to protect 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 our subsidiaries 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 and our subsidiaries’ liquidity and financing efforts;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries’ counterparties, affiliates, and customers to meet their obligations;
- The 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 ability to use tax credit and loss carryforwards;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed timely or within budgets (such as the proposed merger with Wisconsin Energy);

- 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 financial performance of ATC and its corresponding contribution to our earnings;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file with the SEC.

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
(Millions, except per share data)	2014	2013	2014	2013
Utility revenues	$625.1	$606.9	$3,047.9	$2,425.1
Nonregulated revenues	562.8	522.8	2,497.5	1,498.8
Total revenues	1,187.9	1,129.7	5,545.4	3,923.9
Utility cost of fuel, natural gas, and purchased power	228.6	222.8	1,571.8	1,083.9
Nonregulated cost of sales	510.0	475.3	2,334.0	1,360.0
Operating and maintenance expense	289.8	282.3	988.7	866.1
Depreciation and amortization expense	73.3	69.6	217.5	196.0
Taxes other than income taxes	26.3	24.4	79.9	76.4
Merger transaction costs	2.5	—	8.4	—
Goodwill impairment loss	—	—	6.7	—
Transaction costs related to sale of IES's retail energy business	0.9	—	1.7	—
Gain on sale of UPPCO, net of transaction costs	(86.3)	—	(85.4)	—
Gain on abandonment of IES's Winnebago Energy Center	(4.1)	—	(4.1)	—
Operating income	146.9	55.3	426.2	341.5
Earnings from equity method investments	24.5	23.1	71.3	68.2
Miscellaneous income	6.4	12.1	17.4	23.3
Interest expense	38.1	33.1	115.9	91.0
Other income (expense)	(7.2)	2.1	(27.2)	0.5
Income before taxes	139.7	57.4	399.0	342.0
Provision for income taxes	56.8	18.0	154.8	124.3
Net income from continuing operations	82.9	39.4	244.2	217.7
Discontinued operations, net of tax	1.1	(0.6)	0.9	4.7
Net income	84.0	38.8	245.1	222.4
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	—	0.1	0.1
Net income attributed to common shareholders	$83.3	$38.1	$242.9	$220.2
Average shares of common stock				
Basic	80.2	79.8	80.2	79.3
Diluted	81.1	80.2	80.6	79.9
Earnings per common share (basic)				
Net income from continuing operations	$1.03	$0.49	$3.02	$2.72
Discontinued operations, net of tax	0.01	(0.01)	0.01	0.06

Earnings per common share (basic)	$1.04	$0.48	$3.03	$2.78
Earnings per common share (diluted)				
Net income from continuing operations	$1.01	$0.48	$3.00	$2.70
Discontinued operations, net of tax	0.01	(0.01)	0.01	0.06
Earnings per common share (diluted)	$1.02	$0.47	$3.01	$2.76
Dividends per common share declared	$0.68	$0.68	$2.04	$2.04

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Net income	$84.0	$38.8	$245.1	$222.4
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net gains arising during period, net of tax of an insignificant amount for all periods presented	—	—	—	0.7
Reclassification of net losses (gains) to net income, net of tax of $0.2 million, $0.2 million, $1.1 million, and $1.7 million, respectively	0.1	0.3	(0.3)	2.7
Cash flow hedges, net	0.1	0.3	(0.3)	3.4
Defined benefit plans				
Pension and other postretirement benefit costs arising during period, net of tax of an insignificant amount for all periods presented	—	—	(0.1)	—
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.2 million, $0.4 million, $0.7 million, and $1.2 million, respectively	0.4	0.6	1.2	1.8
Defined benefit plans, net	0.4	0.6	1.1	1.8
Other comprehensive income, net of tax	0.5	0.9	0.8	5.2
Comprehensive income	84.5	39.7	245.9	227.6
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	—	0.1	0.1
Comprehensive income attributed to common shareholders	$83.8	$39.0	$243.7	$225.4

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)	September 30	December 31
(Millions, except share and per share data)	2014	2013
Assets		
Cash and cash equivalents	$16.1	$ 22.3
Accounts receivable and accrued unbilled revenues, net of reserves of $65.5 and $49.4, respectively	756.5	1,037.0
Inventories	407.4	253.1
Assets from risk management activities	242.4	239.5
Regulatory assets	104.3	127.4
Assets held for sale	10.4	277.9
Deferred income taxes	76.1	31.4
Prepaid taxes	60.7	146.9
Other current assets	83.1	87.4
Current assets	1,757.0	2,222.9
Property, plant, and equipment, net of accumulated depreciation of $3,363.8 and $3,236.6, respectively	6,661.4	6,211.4
Regulatory assets	1,316.1	1,361.4
Assets from risk management activities	98.5	75.4
Equity method investments	568.9	540.9
Goodwill	655.4	662.1
Other long-term assets	327.6	169.4
Total assets	$11,384.9	$ 11,243.5
Liabilities and Equity		
Short-term debt	$392.5	$ 326.0
Current portion of long-term debt	—	100.0
Accounts payable	622.4	604.8
Liabilities from risk management activities	165.7	163.8
Accrued taxes	72.6	80.9
Regulatory liabilities	130.7	101.1
Liabilities held for sale	—	49.1
Other current liabilities	245.4	228.8
Current liabilities	1,629.3	1,654.5
Long-term debt	2,956.3	2,956.2
Deferred income taxes	1,494.1	1,390.3
Deferred investment tax credits	60.4	57.6
Regulatory liabilities	439.5	383.7
Environmental remediation liabilities	558.1	600.0
Pension and other postretirement benefit obligations	121.0	200.8
Liabilities from risk management activities	70.2	62.8
Asset retirement obligations	509.6	491.0
Other long-term liabilities	151.4	133.2
Long-term liabilities	6,360.6	6,275.6

Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,534,171 shares outstanding	80.0	79.9
Additional paid-in capital	2,660.7	2,660.5
Retained earnings	646.5	567.1
Accumulated other comprehensive loss	(22.4)	(23.2)
Shares in deferred compensation trust	(20.9)	(23.0)
Total common shareholders' equity	3,343.9	3,261.3
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding	51.1	51.1
Noncontrolling interest in subsidiaries	—	1.0
Total liabilities and equity	$11,384.9	$ 11,243.5

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(Millions)	Nine Months Ended September 30 2014	2013
Operating Activities		
Net income	$245.1	$222.4
Adjustments to reconcile net income to net cash provided by operating activities		
Goodwill impairment loss	6.7	—
Depreciation and amortization expense	217.5	196.0
Recoveries and refunds of regulatory assets and liabilities	46.5	35.2
Net unrealized gains on energy contracts	(27.9)	(17.3)
Bad debt expense	39.6	22.2
Pension and other postretirement expense	15.8	47.4
Pension and other postretirement contributions	(95.4)	(65.0)
Deferred income taxes and investment tax credits	53.5	131.7
Gain on sale of UPPCO	(86.5)	—
Equity income, net of dividends	(15.4)	(14.1)
Termination of tolling agreement with Fox Energy Company LLC	—	(50.0)
Other	17.5	25.5
Changes in working capital		
Accounts receivable and accrued unbilled revenues	257.9	80.6
Inventories	(158.5)	(70.1)
Other current assets	60.1	(31.4)
Accounts payable	(28.0)	21.7
Other current liabilities	69.4	(22.6)
Net cash provided by operating activities	617.9	512.2
Investing Activities		
Capital expenditures	(590.9)	(474.7)
Proceeds from sale of UPPCO	332.2	—
Capital contributions to equity method investments	(14.6)	(10.2)
Rabbi trust funding related to potential change in control	(113.0)	—
Acquisition of Fox Energy Company LLC	—	(391.6)
Acquisitions at IES	—	(12.4)
Grant received related to Crane Creek wind project	—	69.0
Other	(2.4)	0.1
Net cash used for investing activities	(388.7)	(819.8)
Financing Activities		
Short-term debt, net	66.5	(294.4)
Borrowing on term credit facility	—	200.0
Issuance of long-term debt	—	724.0
Repayment of long-term debt	(100.0)	(187.0)
Proceeds from stock option exercises	20.0	38.5
Shares purchased for stock-based compensation	(45.1)	(2.0)
Payment of dividends		
Preferred stock of subsidiary	(2.3)	(2.3)
Common stock	(162.3)	(151.6)

Other	(12.2)	(18.9)
Net cash (used for) provided by financing activities	(235.4)	306.3
Net change in cash and cash equivalents	(6.2)	(1.3)
Cash and cash equivalents at beginning of period	22.3	27.4
Cash and cash equivalents at end of period	$16.1	$26.1
Cash paid for interest	$88.1	$60.7
Cash received for income taxes	$(6.5)	$(2.6)

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

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INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
September 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 statements of comprehensive income, condensed consolidated balance sheets, 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 Integrys Energy Group, Inc.

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.

Reclassification

Assets and liabilities associated with the sale of UPPCO and the sale of eight ITF compressed natural gas fueling stations were reclassified as held for sale on our December 31, 2013, balance sheet to be consistent with the current period presentation. See Note 4, Dispositions, for more information on these sales.

Note 2—Proposed Merger with Wisconsin Energy Corporation

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

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

This transaction was approved unanimously by the Boards of Directors of both companies. It is subject to approvals from the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. In addition, this transaction is subject to the approval of the shareholders of both companies, for which special shareholder meetings will be held on November 21, 2014. On October 24, 2014, the Department of Justice closed its review of the transaction and the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Act. This transaction is also subject to other customary closing conditions. We expect the transaction to close in the summer of 2015.

Note 3—Acquisitions

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

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

Acquisition of Fox Energy Center

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

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

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

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

(1) Relates to the electric utility segment.

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

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

WPS received regulatory approval to defer incremental costs incurred in 2013 associated with the purchase of the facility. These costs are included in WPS's 2015 proposed retail electric rate increase. See Note 22, Regulatory Environment, for more information. WPS's 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 WPS. The plant is now part of WPS's regulated fleet, used to serve its customers.

Note 4—Dispositions

Dispositions

IES Segment – Sale of IES Retail Energy Business

On November 1, 2014, we sold IES's retail energy business to Exelon Generation Company, LLC (Exelon) for $319.2 million. The purchase price is subject to adjustments for working capital. Based on the terms of the sale agreement and the carrying values of assets and liabilities being sold, had the transaction closed on September 30, 2014, we would have recorded a pre-tax loss on the sale of approximately $29 million. This amount is subject to change based on the values at the closing date, including values associated with forward energy prices. Included in the sale transaction are commodity contracts that do not meet the GAAP definition of derivative instruments, and therefore are not reflected on the balance sheets. In accordance with GAAP, expected gains or losses related to nonderivative commodity contracts are not recognized until the contracts are settled. As part of the purchase agreement, we will continue to hold guarantees supporting the IES retail energy business for up to six months following the sale. Exelon is obligated under the purchase agreement to replace these guarantees with its own credit support for the IES retail energy business. See Note 14, Guarantees, for more information. Following the sale, we are providing certain administrative and operational services to Exelon during a transition period of up to 15 months.

The retail energy business consisted of mostly financial assets and liabilities; therefore, it did not qualify as held for sale under the applicable accounting guidance. In the third quarter of 2014, we early adopted the guidance in FASB ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." Under this guidance, the results of operations of a component of a business that is sold are only accounted for as discontinued operations if the sale represents a shift in strategy for the entity. The sale of the retail energy business is a result of a previously announced shift in our strategy to focus on our regulated businesses. Therefore, its results of operations will be classified as discontinued operations beginning in the fourth quarter of 2014.

The June 2014 announcement of the potential sale triggered an interim goodwill impairment test. See Note 9, Goodwill and Other Intangible Assets, for more information.

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Electric Utility Segment – Sale of UPPCO

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP (BBIP) for $332.2 million ($199.3 million after-tax). The purchase price is still subject to potential adjustments for working capital. In the third quarter of 2014, we recorded a pre-tax gain of $86.5 million related to the sale of UPPCO. On the statements of income, the gain is presented net of transaction costs of $0.2 million and $1.1 million for the three and nine months ended September 30, 2014, respectively. Following the sale, we are providing certain administrative and operational services to UPPCO during a transition period of 18 to 30 months.

The sale of UPPCO did not meet the requirements under the applicable accounting guidance to qualify as discontinued operations as WPS has significant continuing cash flows related to certain power purchase transactions with UPPCO that are continuing after the sale. Therefore, UPPCO's results of operations through the sale date remain in continuing operations.

The following table shows the carrying values of the major classes of assets and liabilities related to UPPCO classified as held for sale on the balance sheets:

(Millions)	As of the Closing Date in August 2014	December 31, 2013
Current assets	$24.4	$26.5
Property, plant, and equipment, net of accumulated depreciation of $91.3 and $88.9, respectively	194.4	193.8
Other long-term assets	72.8	51.6
Total assets	$291.6	$271.9
Current liabilities	$12.6	$16.7
Long-term liabilities	28.6	32.4
Total liabilities	$41.2	$49.1

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

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

On November 1, 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC, a joint venture between ITF and AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of AMP Trillium LLC. The fair value of the CNG fueling stations was $13.8 million. ITF received cash proceeds of $7.6 million, a $3.1 million note receivable from the buyer with a seven year term, and a $3.1 million equity interest in the joint venture to maintain its current ownership interest. Since two of the CNG fueling stations only began operating in October 2014, the purchase price is subject to potential adjustments for construction costs. In November 2014, we recorded a gain of $2.6 million related to the sale of the CNG fueling stations.

In the third quarter of 2014, we early adopted the guidance in FASB ASU 2014-08, as stated previously. The sale of the CNG stations does not represent a shift in our strategy. Therefore, the results of operations of the CNG fueling stations prior to the sale will remain in continuing operations.

For the CNG fueling stations, net property, plant, and equipment of $9.7 million and $5.3 million was classified as held for sale on the balance sheets at September 30, 2014, and December 31, 2013, respectively. These amounts were net of accumulated depreciation of $0.7 million and $0.3 million at September 30, 2014, and December 31, 2013, respectively.

IES Segment – Winnebago Energy Center

In May 2014, a fire significantly damaged the Winnebago Energy Center, a landfill-gas-to-electric facility owned by IES. Due to uncertainty surrounding the amount of the insurance settlement, IES was unable to determine if it would rebuild or abandon the Winnebago Energy Center in the second quarter of 2014. In August 2014, an insurance settlement was reached, and IES decided to abandon the facility. In the third quarter of 2014, IES received insurance proceeds of $5.8 million for the damage caused by the fire and recorded a pre-tax gain of $4.1 million.

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

Discontinued Operations

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

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IES Segment – Potential Sale of Combined Locks Energy Center

IES is currently pursuing the sale of the Combined Locks Energy Center (Combined Locks), a natural gas-fired co-generation facility located in Wisconsin.

Combined Locks had $0.7 million of assets that were classified as held for sale on the balance sheets at September 30, 2014, and December 31, 2013, which included inventories and property, plant, and equipment. During the three and nine months ended September 30, 2014, IES recorded after-tax losses of $0.1 million and $0.3 million, respectively, in discontinued operations related to Combined Locks. During the three and nine months ended September 30, 2013, IES recorded after-tax losses of $0.6 million and $1.4 million, respectively, in discontinued operations related to Combined Locks.

IES Segment – Sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC

In March 2013, WPS Empire State, Inc., a subsidiary of IES, sold all of the membership interests of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse), both of which owned natural gas-fired generation plants located in the state of New York. The sale agreement also included a potential annual payment to IES for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). In September 2014, IES entered into an agreement to receive $2.0 million in settlement of this earn-out agreement. As a result of the settlement agreement, IES reported after-tax earnings of $1.2 million in discontinued operations for Beaver Falls and Syracuse during the three and nine months ended September 30, 2014. During the nine months ended September 30, 2013, IES recorded after-tax earnings of $0.2 million in discontinued operations related to the gain on sale, partially offset by a net loss from operations at Beaver Falls and Syracuse.

Holding Company and Other Segment

During the nine months ended September 30, 2013, we recorded $5.9 million of after-tax gains in discontinued operations at the holding company and other segment. In 2013, we remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. We reduced the provision for income taxes related to these remeasurements.

Note 5—Cash and Cash Equivalents

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

Continuing Operations

Significant noncash transactions related to continuing operations were:

	Nine Months Ended September 30	
(Millions)	2014	2013
Construction costs funded through accounts payable	$169.9	$98.4
Equity issued for employee stock ownership plan	1.7	10.3
Equity issued for stock-based compensation plans	—	16.2
Equity issued for reinvested dividends	—	9.1
Contingent consideration and payables related to the acquisition of Compass Energy Services	—	7.9

At September 30, 2014, restricted cash recorded within other long-term assets on our balance sheet included $113.3 million that was transferred to the rabbi trust, triggered by the proposed merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on the merger. See Note 15, Employee Benefit Plans, for more information on the rabbi trust funding requirements.

Discontinued Operations

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

	Nine Months Ended September 30	
(Millions)	2014	2013
Operating Activities		
Net unrealized losses on energy contracts	$—	$1.5
Deferred income taxes and investment tax credits	0.4	6.0
Remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits	—	(5.8)

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See Note 24, New Accounting Pronouncements, for more information.

Note 6—Risk Management Activities

All of IES's nonhedge derivatives below relate to its retail energy business that was sold on November 1, 2014. See Note 4, Dispositions, for more information.

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

(Millions)	Balance Sheet Presentation *	September 30, 2014 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$7.2	$3.6
Natural gas contracts	Long-term	0.7	0.7
Financial transmission rights (FTRs)	Current	3.4	0.4
Petroleum product contracts	Current	—	0.6
Coal contracts	Current	—	2.3
Coal contracts	Long-term	2.4	0.1
IES Segment			
Nonhedge derivatives			
Natural gas contracts	Current	61.1	46.2
Natural gas contracts	Long-term	29.1	16.2
Electric contracts	Current	170.7	112.6
Electric contracts	Long-term	66.3	53.2
	Current	242.4	165.7
	Long-term	98.5	70.2
Total		$340.9	$235.9

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

(Millions)	Balance Sheet Presentation (1)	December 31, 2013 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$8.3	$1.0
Natural gas contracts	Long-term	1.8	0.1
FTRs (2)	Current	2.1	0.3
Petroleum product contracts	Current	0.1	—
Coal contracts	Current	—	1.9
Coal contracts	Long-term	0.2	0.8
IES Segment			
Nonhedge derivatives			
Natural gas contracts	Current	57.6	42.9

Natural gas contracts	Long-term	29.5	18.6
Electric contracts	Current	172.0	117.7
Electric contracts	Long-term	43.9	43.3
	Current	240.1	163.8
	Long-term	75.4	62.8
Total		$315.5	$226.6

(1) We classify assets and liabilities from risk management activities as current or long-term based on the maturities of the underlying contracts.

(2) Includes an insignificant risk management asset that was classified as held for sale at UPPCO. See Note 4, Dispositions, for more information.

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

	September 30, 2014		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$11.3	$4.0	$7.3
IES segment	326.8	195.5	131.3
Total	338.1	199.5	138.6
Derivative assets not subject to master netting or similar arrangements	2.8		2.8
Total risk management assets	$340.9		$141.4
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$5.3	$4.4	$0.9
IES segment	226.8	200.0	26.8
Total	232.1	204.4	27.7
Derivative liabilities not subject to master netting or similar arrangements	3.8		3.8
Total risk management liabilities	$235.9		$31.5

	December 31, 2013		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$12.3	$2.1	$10.2
IES segment	301.9	178.1	123.8
Total	314.2	180.2	134.0
Derivative assets not subject to master netting or similar arrangements	1.3		1.3
Total risk management assets	$315.5		$135.3
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$1.4	$1.4	$—
IES segment	222.1	178.1	44.0
Total	223.5	179.5	44.0
Derivative liabilities not subject to master netting or similar arrangements	3.1		3.1
Total risk management liabilities	$226.6		$47.1

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)	September 30, 2014	December 31, 2013	
Cash collateral provided to others: [1]			
Related to contracts under master netting or similar arrangements [3]	$54.3	$ 37.6	[2]
Other	1.1	1.1	
Cash collateral received from others related to contracts under master netting or similar arrangements [1]	—	0.7	

(1) 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.

(2) Includes an insignificant amount that was classified as held for sale at UPPCO. See Note 4, Dispositions, for more information.

(3) Includes $48.6 million and $32.7 million at September 30, 2014, and December 31, 2013, respectively, related to IES's retail energy business, which was sold on November 1, 2014.

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Certain of our derivative and nonderivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The following table shows the aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a liability position:

(Millions)	September 30, 2014	December 31, 2013
Utility segments	$3.4	$0.6
IES segment	58.6	76.7

If all of the credit risk-related contingent features contained in commodity instruments (including derivatives, nonderivatives, normal purchase and normal sales contracts, and applicable payables and receivables) had been triggered, our collateral requirement would have been as follows:

(Millions)	September 30, 2014	December 31, 2013
Collateral that would have been required:		
Utility segments	$0.6	$—
IES segment	182.9	197.6
Collateral already satisfied:		
IES segment — Letters of credit	5.0	4.5
Collateral remaining:		
Utility segments	0.6	—
IES segment	177.9	193.1

Utility Segments

Non-Hedge Derivatives

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

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

	September 30, 2014			December 31, 2013		
(Millions)	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	2,367.1	1.9	N/A	3,124.8	29.3	N/A
FTRs (kilowatt-hours)	N/A	N/A	5,644.0	N/A	N/A	3,633.1
Petroleum products (barrels)	0.1	—	N/A	0.1	—	N/A
Coal (tons)	3.4	—	N/A	4.8	—	N/A

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

		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	Financial Statement Presentation	2014	2013	2014	2013
Natural gas	Balance Sheet — Regulatory assets (current)	$(3.5)	$(0.5)	$(3.6)	$6.9
Natural gas	Balance Sheet — Regulatory assets (long-term)	(0.4)	1.8	(0.6)	1.6

Natural gas	Balance Sheet — Regulatory liabilities (current)	(1.7)	(0.4)	(1.7)	(0.2)
Natural gas	Balance Sheet — Regulatory liabilities (long-term)	(0.2)	—	(0.5)	(0.3)
Natural gas	Income Statement — Operating and maintenance expense	(0.2)	(0.1)	(0.1)	(0.2)
FTRs	Balance Sheet — Regulatory assets (current)	0.6	0.8	(0.3)	—
FTRs	Balance Sheet — Regulatory liabilities (current) *	(0.2)	(0.2)	0.9	(0.3)
Petroleum	Balance Sheet — Regulatory assets (current)	(0.4)	0.1	(0.4)	—
Petroleum	Balance Sheet — Regulatory liabilities (current)	(0.1)	—	(0.1)	—
Petroleum	Income Statement — Operating and maintenance expense	(0.4)	(0.2)	(0.3)	(0.2)
Coal	Balance Sheet — Regulatory assets (current)	(0.9)	(0.6)	(1.0)	2.1
Coal	Balance Sheet — Regulatory assets (long-term)	0.1	0.2	0.7	4.2
Coal	Balance Sheet — Regulatory liabilities (current)	—	—	—	(0.3)
Coal	Balance Sheet — Regulatory liabilities (long-term)	(0.2)	1.5	2.3	(0.7)

* Includes insignificant unrealized gains recorded at UPPCO, which was sold in August 2014. See Note 4, Dispositions, for more information.

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IES Segment

Nonhedge Derivatives

IES entered into physical and financial derivative contracts to manage commodity price risk primarily associated with retail electric and natural gas customer contracts.

IES had the following notional volumes of outstanding derivative contracts:

	September 30, 2014		December 31, 2013	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity contracts				
Natural gas (therms)	1,432.3	1,182.5	1,199.9	1,065.4
Electric (kilowatt-hours)	40,987.7	23,657.9	49,186.3	30,813.8

Gains (losses) related to derivative contracts were recognized currently in earnings, as shown in the table below:

		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	Income Statement Presentation	2014	2013	2014	2013
Natural gas	Nonregulated revenue	$25.9	$(21.1)	$(1.0)	$16.1
Natural gas	Nonregulated cost of sales	(20.5)	25.0	7.5	(9.5)
Natural gas	Nonregulated revenue (reclassified from accumulated OCI) *	—	—	—	(0.2)
Electric	Nonregulated revenue	4.1	36.0	180.2	22.4
Electric	Nonregulated cost of sales	—	(6.6)	2.0	2.1
Electric	Nonregulated revenue (reclassified from accumulated OCI) *	—	(0.2)	—	(3.2)
Total		$9.5	$33.1	$188.7	$27.7

* Represents amounts reclassified from accumulated other comprehensive loss (OCI) related to cash flow hedges that were dedesignated in prior periods.

Note 7—Investment in ATC

Our electric transmission investment segment consists of WPS Investments LLC’s ownership interest in ATC, which was approximately 34% at September 30, 2014. ATC is a for-profit, transmission-only company regulated by FERC.

The following table shows changes to our investment in ATC:

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Balance at the beginning of period	$527.3	$492.2	$508.4	$476.6
Add: Earnings from equity method investment	23.4	22.3	68.9	66.0
Add: Capital contributions	3.4	3.4	13.6	10.2
Less: Dividends received	18.5	17.8	55.3	52.7
Balance at the end of period	$535.6	$500.1	$535.6	$500.1

Financial data for all of ATC is included in the following tables:

	Three Months Ended September 30	Nine Months Ended September 30

(Millions)	2014	2013	2014	2013
Income statement data				
Revenues	$163.7	$160.4	$487.0	$464.3
Operating expenses	76.6	77.5	229.6	217.2
Other expense	21.6	20.2	65.1	62.6
Net income	$65.5	$62.7	$192.3	$184.5

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(Millions)	September 30, 2014	December 31, 2013
Balance sheet data		
Current assets	$72.6	$80.7
Noncurrent assets	3,686.8	3,509.5
Total assets	$3,759.4	$3,590.2
Current liabilities	$455.9	$381.5
Long-term debt	1,550.0	1,550.0
Other noncurrent liabilities	140.5	126.1
Shareholders' equity	1,613.0	1,532.6
Total liabilities and shareholders' equity	$3,759.4	$3,590.2

Note 8—Inventories

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the Last-in, First-out (LIFO) cost method. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. At September 30, 2014, all LIFO layers were replenished, and the LIFO liquidation balance was zero.

Note 9—Goodwill and Other Intangible Assets

The following table shows changes to our goodwill balances by segment during the nine months ended September 30, 2014:

(Millions)	Natural Gas Utility	IES	Holding Company and Other	Total
Balance as of January 1, 2014				
Gross goodwill	$933.5	$6.6	$19.6	$959.7
Accumulated impairment losses	(297.6)	—	—	(297.6)
Net goodwill	635.9	6.6	19.6	662.1
Rounding adjustment	(0.1)	0.1	—	—
Goodwill impairment loss	—	(6.7)	—	(6.7)
Balance as of September 30, 2014				
Gross goodwill	933.5	6.7	19.6	959.8
Accumulated impairment losses	(297.7)	(6.7)	—	(304.4)
Net goodwill	$635.8	$—	$19.6	$655.4

In June 2014, we announced that we were in the late stages of a plan to sell IES's retail energy business. In anticipation of this divestiture, IES performed an interim goodwill impairment analysis. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss of $6.7 million in the second quarter of 2014. This goodwill impairment loss reflected the offers received for IES's retail energy business. See Note 4, Dispositions, for more information on the sale of IES's retail energy business.

In the second quarter of 2014, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of April 1, 2014. No impairments resulted from our annual impairment tests. As discussed above, IES recorded a goodwill impairment loss as a result of an interim test in June 2014.

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The identifiable intangible assets other than goodwill listed below are part of other current and long-term assets on the balance sheets. Intangible assets associated with IES's retail energy business are included in the table along with all of our other intangible assets other than goodwill. See Note 4, Dispositions, for more information on the sale of IES's retail energy business.

(Millions)	September 30, 2014 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	December 31, 2013 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Contractual service agreements [1]	$15.6	$ (3.5)	$12.1	$15.6	$ (1.8)	$13.8
Customer-related [2]	26.8	(16.9)	9.9	26.8	(15.7)	11.1
Renewable energy credits [3]	7.4	—	7.4	8.4	—	8.4
Customer-owned equipment modifications [4]	4.0	(1.1)	2.9	4.0	(0.9)	3.1
Patents/intellectual property [5]	3.4	(0.7)	2.7	3.4	(0.5)	2.9
Nonregulated easements [6]	3.9	(1.4)	2.5	3.7	(1.1)	2.6
Compressed natural gas fueling contract assets [7]	5.6	(3.3)	2.3	5.6	(2.7)	2.9
Natural gas and electric contract assets [8]	3.8	(2.3)	1.5	3.9	(0.5)	3.4
Other	0.5	(0.3)	0.2	0.5	(0.3)	0.2
Total	$71.0	$ (29.5)	$41.5	$71.9	$ (23.5)	$48.4
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name [9]	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name [9]	1.5	—	1.5	1.5	—	1.5
Total intangible assets	$81.2	$ (29.5)	$51.7	$82.1	$ (23.5)	$58.6

(1) Represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at the Fox Energy Center. In October 2014, WPS received approval from the PSCW to upgrade the combustion turbine generators at the Fox Energy Center earlier than planned. As a result of this approval, WPS shortened the amortization period of one of its service agreements. The remaining weighted-average amortization period for these intangible assets at September 30, 2014, was approximately four years. Since WPS has approval from the PSCW to recover the value of its service agreements from customers over seven years, the increase in amortization due to the shorter amortization period will be recorded to a regulatory asset. This regulatory asset will be amortized to reflect the seven-year recovery period.

(2) Represents customer relationship assets associated with PELLC’s former nonregulated retail natural gas and electric operations, ITF's compressed natural gas fueling operations, and IES's retail natural gas operations. The net carrying amounts at September 30, 2014, and December 31, 2013, included $8.3 million and $9.3 million, respectively, of intangible assets related to IES's retail energy business. The remaining weighted-average amortization period at September 30, 2014, for the intangible assets not associated with IES's retail energy business was approximately 12 years.

(3) Used at IES to comply with state Renewable Portfolio Standards and to support customer commitments. All of these intangible assets related to IES's retail energy business at September 30, 2014, and December 31, 2013.

(4) Relates to modifications made by IES and ITF to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at September 30, 2014,

of approximately ten years.

(5) Represents the fair value of patents/intellectual property at ITF related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at September 30, 2014, was approximately eight years.

(6) Relates to easements supporting a pipeline at IES. The easements are amortized on a straight-line basis, with a remaining amortization period at September 30, 2014, of approximately ten years.

(7) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at September 30, 2014, was approximately six years.

(8) Represents the fair value of certain natural gas and electric customer contracts acquired by IES during 2013 and 2014 that were not considered to be derivative instruments. All of these intangible assets related to IES's retail energy business at September 30, 2014, and December 31, 2013.

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Amortization recorded in nonregulated cost of sales				
IES's retail energy business	$0.3	$0.2	$1.8	$0.3
Other	0.3	0.4	0.9	1.2
Total Integrys Energy Group Consolidated	$0.6	$0.6	$2.7	$1.5
Amortization recorded in depreciation and amortization expense				
IES's retail energy business	$0.3	$0.5	$1.0	$1.3
Other	0.8	0.8	2.3	1.7
Total Integrys Energy Group Consolidated	$1.1	$1.3	$3.3	$3.0

An insignificant amount of amortization expense was recorded in discontinued operations for the nine months ended September 30, 2013.

The following table shows our estimated amortization expense for the next five years, including amounts recorded through September 30, 2014. The table below does not include amortization expense related to IES's retail energy business, which was sold on November 1, 2014.

	For the Year Ending December 31				
(Millions)	2014	2015	2016	2017	2018
Amortization to be recorded in nonregulated cost of sales	$1.2	$1.1	$0.9	$0.9	$0.8
Amortization to be recorded in depreciation and amortization expense	3.0	3.0	2.9	2.4	1.9
Amortization to be recorded in regulatory assets	0.3	1.0	1.0	0.5	—

Note 10—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	September 30, 2014	December 31, 2013
Commercial paper	$392.5	$326.0
Average interest rate on commercial paper	0.24 %	0.22 %

The commercial paper outstanding at September 30, 2014, had maturity dates ranging from October 1, 2014, through November 3, 2014.

Our average amount of commercial paper borrowings based on daily outstanding balances during the nine months ended September 30, 2014, and 2013, was $287.8 million and $423.0 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	September 30, 2014	December 31, 2013
Revolving credit facility (Integrys Energy Group) (1)	05/17/2014	$—	$275.0
Revolving credit facility (Integrys Energy Group) (1)	05/17/2016	—	200.0

Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	635.0
Revolving credit facility (Integrys Energy Group)	05/08/2019	465.0	—
Revolving credit facility (WPS) [(1)]	05/17/2014	—	135.0
Revolving credit facility (WPS) [(2)]	05/07/2015	135.0	—
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0
Total short-term credit capacity		$1,600.0	$1,610.0
Less:			
Letters of credit issued inside credit facilities		$29.4	$52.4
Commercial paper outstanding		392.5	326.0
Available capacity under existing agreements		$1,178.1	$1,231.6

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

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

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Note 11—Long-Term Debt

(Millions)	September 30, 2014	December 31, 2013
WPS	$1,175.1	$1,175.1
PGL [1]	725.0	725.0
NSG	82.0	82.0
Integrys Energy Group [2]	974.8	1,074.8
Total	2,956.9	3,056.9
Unamortized discount on debt	(0.6)	(0.7)
Total debt	2,956.3	3,056.2
Less current portion	—	100.0
Total long-term debt	$2,956.3	$2,956.2

(1) PGL's $50.0 million of 2.125% Series VV Bonds were subject to a mandatory interest reset on July 1, 2014. The new interest rate on these bonds is 3.90%, and they are due in March 2030.

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

On November 3, 2014, PGL issued $200.0 million of 4.21% Series BBB Bonds. These bonds are due in November 2044. A portion of the proceeds was used to redeem PGL's $75.0 million 4.875% series QQ Bonds.

Note 12—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 attributable to continuing operations:

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Effective tax rate	40.7 %	31.4 %	38.8 %	36.3 %

Our effective tax rate normally differs from the federal statutory tax rate of 35% due to additional provision for multistate income tax obligations. Other significant items that had an impact on our effective tax rates are noted below.

Our effective tax rate for the three months ended September 30, 2013, was lower than the federal statutory rate of 35%. This difference was primarily due to a $3.7 million decrease in our provision for income taxes as a result of the reversal of a regulatory liability. This amount was related to deferred income taxes that had been recorded in prior years as a result of scheduled income tax rate changes in Illinois. We recorded the reversal based on the income tax treatment included in the 2013 final rate order for PGL and NSG.

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

Note 13—Commitments and Contingencies

(a) Unconditional Purchase Obligations and Purchase Order Commitments

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

			Payments Due By Period					
(Millions)	Year Contracts Extend Through	Total Amounts Committed	2014	2015	2016	2017	2018	Later Years
Natural gas utility supply and transportation	2028	$763.8	$57.7	$186.9	$168.3	$129.5	$77.0	$144.4
Electric utility								
Purchased power	2029	944.0	19.1	118.9	42.3	52.8	55.8	655.1
Coal supply and transportation	2018	124.9	15.6	45.1	21.1	22.2	20.9	—
Total		$1,832.7	$92.4	$350.9	$231.7	$204.5	$153.7	$799.5

We and our subsidiaries also had commitments of $1,043.8 million in the form of purchase orders issued to various vendors at September 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 WPS alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. WPS reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the U.S. District Court (Court) in March 2013, after a public comment period. The final Consent Decree includes:

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

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain Weston and Pulliam units. WPS announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. In July 2014, WPS 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. WPS believes that it will receive approval of this treatment from the PSCW.

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

In May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of September 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 WPS. The NOV alleges violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, WP&L, and Madison Gas and Electric reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million, and

- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain of the Columbia and Edgewater units. As of September 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 proposed by WPS have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

Weston Title V Air Permit:
In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, WPS challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also 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. The Petitions for Judicial Review, by all parties, have been stayed pending the

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resolution of the contested cases. In May 2014, the WDNR referred the contested case to the administrative law judge, and a schedule was set for dispositive motions, which have now been fully briefed. WPS filed an application to amend some permit terms that, if accepted, would resolve many of the outstanding issues. In September 2014, the WDNR issued a draft permit that resolves several issues raised in the contested case by WPS. If these permit terms are finalized, WPS will withdraw nine claims under the Petition. The new permit does raise an additional issue regarding the sorbent injection rate, which WPS will challenge and is discussed below.

In May 2014, the WDNR issued an NOV alleging that WPS failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System certification. WPS and the WDNR have begun discussing resolution of this matter. In May 2014, the WDNR issued a Notice of Inquiry (NOI) to WPS alleging that WPS failed to comply with excess emission summary reporting requirements in the 2013 Weston Title V permit. WPS believes that the requirements identified in the NOV and NOI are stayed pursuant to state law pending the outcome of the Weston Title V air permit contested case and has filed a motion with the administrative law judge requesting confirmation of the stay. Briefing has been completed on this issue, and we anticipate a decision from the administrative law judge in the fourth quarter of 2014.

We do not expect these matters to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule 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.

WPS will be in compliance with the State of Wisconsin's mercury rule at the end of 2014. In addition, WPS is making progress toward compliance with the MATS rule in 2015. WPS estimated capital costs of approximately $9 million for its wholly owned plants to achieve the required reductions for MATS compliance, of which approximately $5 million has been expended as of September 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 WPS, challenged in the United States Court of Appeals (Court of Appeals) for the District of Columbia Circuit (D.C. Circuit). The new rule was to become effective in January 2012. However, in December 2011, the CSAPR requirements were stayed by the D.C. Circuit and a previous rule, the Clean Air Interstate Rule (CAIR), was implemented during the stay period. In August 2012, the D.C. Circuit issued their ruling vacating and remanding CSAPR and simultaneously reinstating CAIR pending the issuance of a replacement rule by the EPA. The case was appealed to the United States Supreme Court (Supreme Court), and in April 2014, the Supreme Court upheld the CSAPR rule and remanded the case to the Court of Appeals for the D.C. Circuit.

In June 2014, the EPA requested that the Court of Appeals lift the stay of CSAPR. Further, the EPA asked the Court of Appeals 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. In October 2014, the Court of Appeals granted the EPA's request and lifted the stay on CSAPR. There are remaining issues before the Court of Appeals, and there will need to be additional changes before CSAPR is implemented. As a result, it is premature to speculate on what additional controls or other actions, if any, WPS may be required to implement. WPS expects to recover any future compliance costs in future rates.

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

Manufactured Gas Plant Remediation

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

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Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. Our balance sheets include liabilities of $557.9 million that we have estimated and accrued for as of September 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 September 30, 2014, cash expenditures for environmental remediation not yet recovered in rates were $56.6 million. Our balance sheets include a regulatory asset of $614.5 million at September 30, 2014, which is net of insurance recoveries, related to the expected recovery through rates of both cash expenditures and estimated future expenditures.

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

Note 14—Guarantees

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at September 30, 2014	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$718.3	$478.3	$4.6	$235.4
Standby letters of credit (2)	34.6	33.8	0.7	0.1
Surety bonds (3)	34.5	34.5	—	—
Other guarantees (4)	55.2	1.5	—	53.7
Total guarantees (5)	$842.6	$548.1	$5.3	$289.2

(1) Consists of (a) $548.9 million, and $5.0 million to support the business operations of IES, and IBS, respectively, and (b) $119.0 million, $45.0 million, and $0.4 million related to natural gas supply at MERC, MGU, and ITF, respectively. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $33.0 million issued to support IES’s operations, $1.6 million issued to support ITF, MERC, MGU, NSG, PGL, and WPS, along with $0.5 million issued to support UPPCO operations. These amounts are not reflected on our balance sheets. The $0.5 million of UPPCO letters of credit were canceled in October 2014. See Note 4, Dispositions, for more information on the sale of UPPCO.

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

(4) Consists of (a) $35.0 million to support IES's future payment obligations related to its distributed solar generation projects. This guarantee is not reflected on our balance sheets; (b) $10.0 million related to the sale agreement for

IES's Texas retail marketing business, which included a number of customary representations, warranties, and indemnification provisions. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the law; (c) $1.8 million related to the sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC. IES guaranteed the buyer's performance under certain derivative contracts that the buyer assumed from WPS Empire State, Inc. in conjunction with the sale; (d) $2.4 million related to the performance of an operating and maintenance agreement by ITF; and (e) $6.0 million related to other indemnifications primarily for workers compensation coverage. The amounts discussed in items (c) through (e) above are not reflected on our balance sheets.

(5) Consists of $586.0 million of guarantees that will be eliminated within six months after the sale of IES's retail energy business. See Note 4, Dispositions, for more information on the sale of IES's retail energy business. As of November 1, 2014, we assumed $41.6 million of guarantees from IES related to distributed solar generation projects.

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Note 15—Employee Benefit Plans

Defined Benefit Plans

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

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended September 30		Nine Months Ended September 30		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013	2014	2013	2014	2013
Service cost	$6.2	$7.5	$18.7	$22.6	$5.2	$6.3	$15.9	$18.7
Interest cost	19.0	17.8	58.0	53.4	5.7	6.2	18.0	18.6
Expected return on plan assets	(28.0)	(26.4)	(85.4)	(79.1)	(8.3)	(7.7)	(25.0)	(23.0)
Loss on plan settlement	—	—	0.9	—	—	—	—	—
Amortization of prior service cost (credit)	0.1	1.0	0.4	3.0	(2.7)	(0.7)	(6.8)	(1.9)
Amortization of net actuarial losses	8.3	14.2	25.3	42.5	0.9	2.1	2.4	6.3
Net periodic benefit cost	$5.6	$14.1	$17.9	$42.4	$0.8	$6.2	$4.5	$18.7

Prior service costs (credits) and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are recorded in accumulated other comprehensive income for our nonregulated entities and as net regulatory assets or liabilities for our regulated utilities.

In August 2014, we closed on the sale of UPPCO. The funded status of pension and other postretirement-related assets and liabilities transferred with the sale was a net asset of approximately $26 million. See Note 4, Dispositions, for more information. This net asset consisted of approximately $150 million of pension and other postretirement benefit plan assets, and approximately $124 million of benefit obligations.

In March 2014, we remeasured the obligations of certain other postretirement benefit plans. 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 nine months ended September 30, 2014, we contributed $95.2 million to our pension plans and $0.2 million to our other postretirement benefit plans. We expect to contribute an additional $5.0 million to our pension plans and $10.6 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. Of the remaining contributions for 2014, contributions of $2.0 million will be funded through a transfer of assets from the rabbi trust for certain nonqualified pension plans. See the discussion below in regard to the triggering of the full funding of the rabbi trust.

Rabbi Trust Funding Requirement

Historically, our deferred compensation programs were partially funded through shares of common stock held in a rabbi trust. The Agreement and Plan of Merger entered into with Wisconsin Energy Corporation in June 2014 triggered the potential change in control provisions in the rabbi trust agreement. These provisions required the full funding of the present value of each participant's total benefit under the deferred compensation program and certain nonqualified pension plans. As a result, $65.0 million was moved to the rabbi trust in June 2014, and an additional $64.8 million, consisting of cash and exchange-traded funds, was moved to the rabbi trust in July 2014. These amounts were included in other long-term assets on the balance sheet as of September 30, 2014. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on the merger.

Note 16—Stock-Based Compensation

In May 2014, our shareholders approved the 2014 Omnibus Incentive Compensation Plan (2014 Omnibus Plan). Under the provisions of the 2014 Omnibus Plan, the number of shares of stock that may be issued in satisfaction of plan awards may not exceed 3,000,000 shares, plus any shares forfeited under prior plans. No single employee who is our chief executive officer, chief financial officer, or any one of our other three highest compensated officers (including officers of our subsidiaries) can be granted stock options for more than 1,000,000 shares or receive a payout in excess of 250,000 shares for performance stock rights during any calendar year. Additional awards will not be issued under prior plans, although the plans continue to exist for purposes of the existing outstanding stock-based compensation awards. At September 30, 2014, stock options, performance stock rights, and restricted share units were outstanding under prior plans.

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

	Three Months Ended September		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Stock options	$0.4	$0.5	$1.2	$1.4
Performance stock rights	1.1	1.2	10.8	4.4
Restricted share units *	1.5	2.5	7.6	7.8
Nonemployee director deferred stock units	0.2	0.2	0.6	0.7
Total stock-based compensation expense	$3.2	$4.4	$20.2	$14.3
Deferred income tax benefit	$1.3	$1.8	$8.1	$5.7

* The three and nine months ended September 30, 2013, include an insignificant amount related to IES's retail energy business. The three and nine months ended September 30, 2014, do not include any amounts related to IES's retail energy business as the estimated forfeiture rate was adjusted in the third quarter of 2014 to reflect the sale.

No stock-based compensation cost was capitalized during the three and nine months ended September 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. The expected stock price volatility is estimated using the 10-year historical volatility of our stock price. 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 nine months ended September 30, 2014, and 2013, was $6.70 and $6.03, respectively.

A summary of stock option activity for the nine months ended September 30, 2014, and information related to outstanding and exercisable stock options at September 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	1,550,374	$ 50.93		
Granted	264,332	55.23		
Exercised	(411,214)	48.63		
Forfeited	(2,542)	55.23		
Outstanding at September 30, 2014	1,400,950	$ 52.41	6.6	$17.4
Exercisable at September 30, 2014	714,317	$ 50.33	4.9	$10.3

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 September 30, 2014. This is calculated as the difference between our closing stock price on September 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 nine months ended September 30, 2014, and 2013, was $7.5 million and $9.0 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $3.0 million and $3.6 million for the nine months ended September 30, 2014, and 2013, respectively.

Effective October 24, 2014, our Board of Directors accelerated the vesting of all unvested stock options held by active employees in order to help mitigate the tax impacts of Section 280G of the Internal Revenue Code on us and certain of our employees. All stock options awarded to active employees also became exercisable as of this date. As a result of this modification, the remaining $1.5 million of unrecognized compensation expense related to unvested and outstanding stock options at September 30, 2014, will be recognized in the fourth quarter of 2014.

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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. The expected stock price 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 September 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 nine months ended September 30, 2014, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value (2)
Outstanding at December 31, 2013	85,749	$ 46.62
Granted	21,146	44.28
Award modifications (1)	64,612	85.09
Adjustment for shares not distributed	(45,748)	43.29
Forfeited	(203)	44.28
Outstanding at September 30, 2014	125,556	$ 67.24

(1) Six months prior to the end of the performance period, employees can no longer change their election to defer the value of their performance stock rights into the deferred compensation plan. As a result, any awards not elected for deferral at this point in the performance period will be settled in our common stock. This changes the classification of these awards from a liability award to an equity award. The change in classification is accounted for as an award modification.

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

The weighted-average grant date fair value of performance stock rights awarded during the nine months ended September 30, 2014, and 2013, was $44.28 and $48.50, per performance stock right, respectively.

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

	Performance Stock Rights
Outstanding at December 31, 2013	198,904
Granted	84,529
Award modifications *	(64,612)
Adjustment for shares not distributed	(39,001)
Forfeited	(813)
Outstanding at September 30, 2014	179,007

* Six months prior to the end of the performance period, employees can no longer change their election to defer the value of their performance stock rights into the deferred compensation plan. As a result, any awards not elected for deferral at this point in the performance period will be settled in our common stock. This changes the classification of these awards from a liability award to an equity award. The change in classification is accounted for as an award

modification.

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of September 30, 2014, was $78.61 per performance stock right.

No shares of common stock were distributed for performance stock rights during the nine months ended September 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 nine months ended September 30, 2013, was $8.8 million. The actual tax benefit realized for the tax deductions from the distribution of shares during the nine months ended September 30, 2013, was $3.6 million.

Effective October 24, 2014, our Board of Directors approved the acceleration of the distribution of certain performance stock rights held by active employees. For those performance stock rights with a performance period ending December 31, 2014, a portion of the estimated distribution will be made in December 2014. This change was made to help mitigate the tax impacts of Section 280G of the Internal Revenue Code on us and certain of our employees.

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As of September 30, 2014, $5.0 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.4 years.

Restricted Share Units

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

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2013	511,301	$ 52.24
Granted	214,953	55.23
Dividend equivalents	17,317	54.45
Vested and released	(208,873)	49.76
Forfeited	(16,730)	54.66
Outstanding at September 30, 2014 *	517,968	$ 54.48

* Includes 94,267 restricted share units that were forfeited on November 1, 2014 related to the sale of IES's retail energy business. See Note 4, Dispositions, for more information on the sale.

The weighted-average grant date fair value of restricted share units awarded during the nine months ended September 30, 2014, and 2013, was $55.23 and $55.93 per unit, respectively.

The total intrinsic value of restricted share unit awards vested and released during the nine months ended September 30, 2014, and 2013, was $11.4 million and $11.6 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted share units during the nine months ended September 30, 2014, and 2013, was $4.6 million and $4.7 million, respectively.

As of September 30, 2014, $9.5 million of compensation cost related to unvested and outstanding restricted share units was expected to be recognized over a weighted-average period of 2.2 years.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. These awards generally vest over one year; therefore, the expense is recognized pro-rata over the year in which the grant occurs. The number of DSUs granted is calculated by dividing a set dollar amount by our closing common stock price on December 31 of the prior year. Nonemployee directors also receive forfeitable dividend equivalents in the form of additional DSUs.

Note 17—Common Equity

We had the following changes to issued common stock during the nine months ended September 30, 2014:

Balance at December 31, 2013	79,919,176
Shares issued	
Employee Stock Ownership Plan	31,764
Stock Investment Plan	12,151
Balance at September 30, 2014	79,963,091

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

Period	Method of meeting requirements
Beginning 02/05/14	Purchasing shares on the open market
02/05/2013 – 02/04/2014	Issued new shares
01/01/2013 – 02/04/2013	Purchased shares on the open market

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The following table reconciles common shares issued and outstanding:

	September 30, 2014		December 31, 2013	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,963,091		79,919,176	
Less:				
Deferred compensation rabbi trust	428,920	$48.73	473,796	$48.50
Total common shares outstanding	79,534,171		79,445,380	

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

Under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we can no longer issue shares of our common stock.

Earnings Per Share

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions, except per share amounts)	2014	2013	2014	2013
Numerator:				
Net income from continuing operations	$82.9	$39.4	$244.2	$217.7
Discontinued operations, net of tax	1.1	(0.6)	0.9	4.7
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	—	0.1	0.1
Net income attributed to common shareholders — basic	$83.3	$38.1	$242.9	$220.2
Effect of dilutive securities				
Stock-based compensation	—	(0.1)	—	(0.1)
Deferred compensation	(0.8)	—	—	—
Net income attributed to common shareholders — diluted	$82.5	$38.0	$242.9	$220.1
Denominator:				
Average shares of common stock — basic	80.2	79.8	80.2	79.3
Effect of dilutive securities				
Stock-based compensation	0.6	0.4	0.4	0.4
Deferred compensation	0.3	—	—	0.2
Average shares of common stock — diluted	81.1	80.2	80.6	79.9
Earnings per common share				
Basic	$1.04	$0.48	$3.03	$2.78

Diluted	1.02	0.47	3.01	2.76

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Stock-based compensation	—	0.4	0.2	0.2
Deferred compensation	—	0.2	0.3	0.1

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Dividend Restrictions

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

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

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

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

As of September 30, 2014, total restricted net assets of consolidated subsidiaries were $1,844.5 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $159.6 million at September 30, 2014.

We also have short-term and long-term debt obligations that contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of outstanding debt obligations. At September 30, 2014, these covenants did not restrict our retained earnings or the payment of any dividends.

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

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

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

Capital Transactions with Subsidiaries

During the nine months ended September 30, 2014, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of	Equity Contributions

	Capital	To Parent	From Parent
IBS	$ —	$ —	$ 25.0
ITF [1]	—	—	45.5
MERC	—	27.0	12.0
MGU	—	13.0	—
PGL [1]	—	—	65.0
UPPCO	—	12.5	94.4
WPS	83.9	—	40.0
WPS Investments, LLC [2]	55.2	—	13.6
Total	$ 139.1	$ 52.5	$ 295.5

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

(2) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us and WPS. In August 2014, UPPCO's ownership interest in WPS Investments, LLC was transferred to us as a result of the sale of UPPCO. At September 30, 2014, the ownership interest held by us and WPS was 88.95% and 11.05%, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2014, all equity contributions to WPS Investments, LLC were made solely by us.

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Note 18—Accumulated Other Comprehensive Loss

The following tables show the changes, net of tax, to our accumulated other comprehensive loss:

(Millions)	Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at the beginning of period	$(3.5)	$(19.4)	$(22.9)	$(3.1)	$(20.1)	$(23.2)
Other comprehensive loss before reclassifications	—	—	—	—	(0.1)	(0.1)
Amounts reclassified out of accumulated other comprehensive loss	0.1	0.4	0.5	(0.3)	1.2	0.9
Net current period other comprehensive income (loss)	0.1	0.4	0.5	(0.3)	1.1	0.8
Balance at the end of period	$(3.4)	$(19.0)	$(22.4)	$(3.4)	$(19.0)	$(22.4)

(Millions)	Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at the beginning of period	$(2.1)	$(34.5)	$(36.6)	$(5.2)	$(35.7)	$(40.9)
Other comprehensive income before reclassifications	—	—	—	0.7	—	0.7
Amounts reclassified out of accumulated other comprehensive loss	0.3	0.6	0.9	2.7	1.8	4.5
Net current period other comprehensive income	0.3	0.6	0.9	3.4	1.8	5.2
Balance at the end of period	$(1.8)	$(33.9)	$(35.7)	$(1.8)	$(33.9)	$(35.7)

The following table shows the reclassifications out of accumulated other comprehensive loss during the three and nine months ended September 30:

(Millions)	Amount Reclassified Three Months Ended September 30		Nine Months Ended September 30		Affected Line Item in the Statements of Income
	2014	2013	2014	2013	
Losses (gains) on cash flow hedges					
Utility commodity derivative contracts	$—	$—	$—	$0.2	Operating and maintenance expense (1) (2)
Nonregulated commodity derivative contracts	—	0.2	—	3.4	Nonregulated revenues (2)
Interest rate hedges	0.3	0.3	0.8	0.8	Interest expense
	0.3	0.5	0.8	4.4	Total before tax
	0.2	0.2	1.1	1.7	Tax expense

	0.1	0.3	(0.3)	2.7	Net of tax
Defined benefit plans					
Amortization of prior service credits	—	(0.1)	(0.1)	(0.2)	[3]
Amortization of net actuarial losses	0.6	1.1	2.0	3.2	[3]
	0.6	1.0	1.9	3.0	Total before tax
	0.2	0.4	0.7	1.2	Tax expense
	0.4	0.6	1.2	1.8	Net of tax
Total reclassifications	$0.5	$0.9	$0.9	$4.5	

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

[2] We no longer designate commodity contracts as cash flow hedges.

[3] These items are included in the computation of net periodic benefit cost. See Note 15, Employee Benefit Plans, for more information.

Note 19—Variable Interest Entities

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. This joint venture was established to own and operate compressed natural gas (CNG) fueling stations. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. At December 31, 2013, ITF was the primary beneficiary of this variable interest entity, and, as a result, we consolidated the assets, liabilities, and statements of income of the joint venture. However, in April 2014, ITF and AMP Americas LLC restructured this joint venture. Due to the restructuring, our influence over the activities that most significantly impact the variable interest entity's economic performance decreased. We have determined that ITF is no longer the primary beneficiary of this variable interest entity and that we are no longer required to consolidate the joint venture. Therefore, we started accounting for this variable interest entity as an equity method investment in April 2014. At September 30, 2014, and December 31, 2013, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was also not significant. On November 1, 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC. See Note 4, Dispositions, for more information.

In 2013, ITF formed EVO Trillium LLC as a joint venture with Environmental Alternative Fuels LLC. ITF owns 15% and Environmental Alternative Fuels LLC owns 85% of the joint venture. This joint venture was established to own and operate CNG fueling stations. We determined that this joint venture is a variable interest entity but that consolidation is not required since we are not its primary beneficiary, as we do not have the power to direct its activities. We instead account for this variable interest entity as an equity method investment. At September 30, 2014, and December 31, 2013, the assets and liabilities on our balance sheets related to our involvement with this variable interest entity consisted of insignificant receivables. Our maximum exposure to loss as a result of involvement with this variable interest entity was also not significant.

We also had a variable interest in an entity through a power purchase agreement at UPPCO that reimbursed an independent power producing entity for coal costs relating to purchased energy. There was no obligation to purchase energy under this 17.5 megawatt agreement. For a variety of reasons, we determined that we were not the primary beneficiary of this variable interest entity and that consolidation was not required. At December 31, 2013, the assets and liabilities on our balance sheets that related to our involvement with this variable interest entity pertained to working capital accounts and represented the amounts we owed for current deliveries of power. In August 2014, we sold UPPCO to Balfour Beatty Infrastructure Partners LP (BBIP), and, as a result, this power purchase agreement was transferred to BBIP. See Note 4, Dispositions, for more information on the sale of UPPCO.

Note 20—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 methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

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

We 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.

When possible, we base the valuations of our risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), and price correlation (for cross commodity contracts). These inputs are available through multiple sources, including exchanges and brokers. Transactions valued using these inputs are classified in Level 2.

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

- While forward price curves may have been based on observable information, significant assumptions may have been made regarding monthly shaping and locational basis differentials.

- Certain transactions were valued using price curves that extended beyond an observable period. Assumptions were made to extrapolate prices from the last observable period through the end of the transaction term, primarily through the use of historically settled data or correlations to other locations.

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

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

All of IES's risk management assets and liabilities below relate to its retail energy business that was sold on November 1, 2014. See Note 4, Dispositions, for more information.

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:

	September 30, 2014			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$2.4	$5.5	$—	$7.9
Financial transmission rights (FTRs)	—	—	3.4	3.4
Coal contracts	—	—	2.4	2.4
IES Segment				
Natural gas contracts	21.2	41.4	27.6	90.2
Electric contracts	89.2	135.4	12.4	237.0
Total Risk Management Assets	$112.8	$182.3	$45.8	$340.9
Investment in exchange-traded funds	$16.3	$—	$—	$16.3
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.8	$3.5	$—	$4.3
Petroleum product contracts	0.6	—	—	0.6
FTRs	—	—	0.4	0.4
Coal contracts	—	—	2.4	2.4
IES Segment				
Natural gas contracts	15.3	30.4	16.7	62.4

Electric contracts	123.5	38.4	3.9	165.8
Total Risk Management Liabilities	$140.2	$72.3	$23.4	$235.9

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(Millions)	December 31, 2013 Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$2.4	$7.7	$—	$10.1
FTRs *	—	—	2.1	2.1
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	0.2	0.2
IES Segment				
Natural gas contracts	16.3	35.2	35.6	87.1
Electric contracts	65.1	134.9	15.9	215.9
Total Risk Management Assets	$83.9	$177.8	$53.8	$315.5
Investment in exchange-traded funds	$15.9	$—	$—	$15.9
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.5	$0.6	$—	$1.1
FTRs	—	—	0.3	0.3
Coal contracts	—	—	2.7	2.7
IES Segment				
Natural gas contracts	14.3	22.0	25.2	61.5
Electric contracts	98.8	58.7	3.5	161.0
Total Risk Management Liabilities	$113.6	$81.3	$31.7	$226.6
Contingent consideration related to the acquisition of Compass Energy Services	$—	$—	$7.8	$7.8

* Includes an insignificant amount that was classified as held for sale at UPPCO. See Note 4, Dispositions, for more information.

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

The following tables show net risk management assets (liabilities) transferred between the levels of the fair value hierarchy:

	IES Segment — Natural Gas Contracts					
	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	—	$—	N/A	0.3
Transfers into Level 3 from	—	0.7	N/A	—	2.5	N/A

	IES Segment — Natural Gas Contracts	
	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013

(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$0.1	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	0.5	$—	N/A	0.3
Transfers into Level 3 from	—	2.3	N/A	—	4.0	N/A

	IES Segment — Electric Contracts					
	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$1.0	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	2.9	$—	N/A	(0.8)
Transfers into Level 3 from	—	0.1	N/A	(0.2)	—	N/A

	IES Segment — Electric Contracts					
	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$ 1.2	$ —	N/A	$ —	$ —
Transfers into Level 2 from	$ —	N/A	11.4	$ —	N/A	4.6
Transfers into Level 3 from	—	6.5	N/A	(0.2)	6.2	N/A

Derivatives were transferred between the levels of the fair value hierarchy primarily due to changes in the source of data used to construct price curves as a result of changes in market liquidity. We recognize transfers between the levels at the value as of the end of the reporting period.

The amounts and percentages 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 September 30, 2014:

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	$ 3.4	$ 0.4	Market-based	Forward market prices ($/megawatt-month) (1)	$187.89
Coal contracts	2.4	2.4	Market-based	Forward market prices ($/ton) (2)	$12.31 – $15.50
IES Segment					
Natural gas contracts	27.6	16.7	Market-based	Forward market prices ($/dekatherm) (3)	($1.94) – $7.71
				Probability of default (4)	11.6% – 51.0%
Electric contracts	12.4	3.9	Market-based	Forward market prices ($/megawatt-hours) (3)	($3.00) – $12.10
				Probability of default (4)	26.0%
				Option volatilities (5)	18.7% – 116.0%

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

(2) Represents third-party forward market pricing.

(3) Represents unobservable basis spreads developed using historical settled prices that are applied to observable market prices at various natural gas and electric locations, as well as unobservable adjustments made to extend observable market prices beyond the quoted period through the end of the transaction term.

(4) Based on Moody's one-year counterparty default percentages.

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

At the utility segments, significant changes in historical settlement prices and forward coal prices would result in a directionally similar significant change in fair value. Significant changes in the unobservable inputs used to value IES's risk management assets and liabilities will not impact us as after November 1, 2014, as these assets and liabilities were included in the sale of IES's retail energy business. See Note 4, Dispositions, for more information.

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

Three Months Ended September 30, 2014	IES Segment			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$5.0	$14.9	$ (6.6)	$5.2	$0.9	$19.4
Net realized and unrealized gains included in earnings	6.2	1.2	2.3	0.3	—	10.0
Net unrealized gains (losses) recorded as regulatory assets or liabilities	—	—	—	0.4	(1.0)	(0.6)
Purchases	—	0.9	—	0.1	—	1.0
Sales	—	—	—	(1.0)*	—	(1.0)
Settlements	(1.0)	(5.7)	4.3	(2.0)	0.1	(4.3)
Net transfers into Level 3	0.7	0.1	—	—	—	0.8
Net transfers out of Level 3	—	(2.9)	—	—	—	(2.9)
Balance at the end of the period	$10.9	$8.5	$ —	$3.0	$—	$22.4
Net unrealized gains included in earnings related to instruments still held at the end of the period	$6.2	$1.2	$ —	$—	$—	$7.4

* Activity relates to FTRs sold in connection with sale of UPPCO. See Note 4, Dispositions, for more information.

Three Months Ended September 30, 2013	IES Segment			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$7.7	$4.1	$ (7.7)	$3.9	$(2.3)	$5.7
Net realized and unrealized gains included in earnings	4.2	1.9	—	1.3	—	7.4
Net unrealized gains (losses) recorded as regulatory assets or liabilities	—	—	—	0.6	(4.5)	(3.9)
Purchases	—	0.7	—	—	—	0.7
Settlements	(2.5)	(4.6)	—	(2.8)	5.6	(4.3)
Net transfers into Level 3	2.5	(0.2)	—	—	—	2.3
Net transfers out of Level 3	(0.3)	0.8	—	—	—	0.5
Balance at the end of the period	$11.6	$2.7	$ (7.7)	$3.0	$(1.2)	$8.4
Net unrealized gains included in earnings related to instruments still held at the end of the period	$4.2	$1.9	$ —	$—	$—	$6.1

Nine Months Ended September 30, 2014	IES Segment			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$10.4	$12.4	$ (7.8)	$1.8	$(2.5)	$14.3
Net realized and unrealized gains included in earnings	0.2	12.8	2.3	0.7	—	16.0
Net unrealized gains recorded as regulatory assets or liabilities	—	—	—	0.6	2.0	2.6
Purchases	—	2.2	—	5.6	—	7.8
Sales	—	(0.7)	—	(1.0)*	—	(1.7)

Settlements	(1.5)	(13.3)	5.5	(4.7)	0.5	(13.5)
Net transfers into Level 3	2.3	6.5	—	—	—	8.8
Net transfers out of Level 3	(0.5)	(11.4)	—	—	—	(11.9)
Balance at the end of the period	$10.9	$8.5	$ —	$3.0	$—	$22.4
Net unrealized gains included in earnings related to instruments still held at the end of the period	$0.2	$12.8	$ —	$—	$—	$13.0

* Activity relates to FTRs sold in connection with sale of UPPCO. See Note 4, Dispositions, for more information.

Nine Months Ended September 30, 2013	IES Segment			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$3.9	$(4.3)	$ —	$2.0	$(6.5)	$(4.9)
Net realized and unrealized gains included in earnings	1.3	7.6	—	1.7	—	10.6
Net unrealized (losses) gains recorded as regulatory assets or liabilities	—	—	—	(0.3)	2.2	1.9
Purchases	7.0	2.3	(7.7)	4.9	—	6.5
Sales	—	—	—	(0.1)	—	(0.1)
Settlements	(4.3)	(4.3)	—	(5.2)	3.1	(10.7)
Net transfers into Level 3	4.0	6.0	—	—	—	10.0
Net transfers out of Level 3	(0.3)	(4.6)	—	—	—	(4.9)
Balance at the end of the period	$11.6	$2.7	$ (7.7)	$3.0	$(1.2)	$8.4
Net unrealized gains included in earnings related to instruments still held at the end of the period	$1.3	$7.6	$ —	$—	$—	$8.9

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Realized and unrealized gains and losses included in earnings related to IES’s risk management assets and liabilities were recorded through nonregulated revenue or nonregulated cost of sales on the statements of income, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through utility 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:

	September 30, 2014		December 31, 2013	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$2,956.3	$3,068.3	$3,056.2	$3,031.6
Preferred stock of subsidiary	51.1	57.0	51.1	61.2

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy.

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

Note 21—Advertising Costs

Costs associated with certain natural gas and electric direct-response advertising campaigns at IES were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. Capitalized direct-response advertising costs, net of accumulated amortization, totaled $4.9 million and $5.2 million as of September 30, 2014, and December 31, 2013, respectively. On November 1, 2014, IES's retail energy business was sold, and these capitalized direct-response advertising costs were included in the sale. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment. We did not record any significant impairments during the three and nine months ended September 30, 2014, and 2013.

Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years. The amortization of direct-response advertising costs was $0.1 million for the three months ended September 30, 2014, and 2013. The amortization of direct-response advertising costs was $1.8 million and $4.1 million for the nine months ended September 30, 2014, and 2013, respectively.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. The following table shows our other advertising expense.

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2014	2013	2014	2013
Other advertising expense				
IES's retail energy business	$1.0	$1.0	$3.3	$4.0
Other	1.3	1.2	2.8	2.6
Total Integrys Energy Group Consolidated	$2.3	$2.2	$6.1	$6.6

Note 22—Regulatory Environment

Wisconsin

2015 Rate Case

In April 2014, WPS 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. WPS's request reflects a 10.60% return on common equity and a target common equity ratio of 50.51% in WPS's regulatory capital structure. In May 2014, WPS filed its 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 is reviewing the new rate design as part of the rate-setting process.

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 WPS's 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 a portion of the remaining 2013 fuel cost over-collections to customers. However, in July 2014, the PSCW authorized WPS 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.

The proposed retail natural gas rate decrease is 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 August 2014, the PSCW staff submitted testimony and recommended a rate increase of $28.7 million for retail electric and a rate decrease of $13.6 million for retail natural gas, which reflected a 10.20% return on common equity. PSCW staff recommended a common equity ratio of 50.27% for WPS's regulatory capital structure. The PSCW held both technical and public hearings in September 2014. In October 2014, WPS issued an initial brief revising its requested retail electric rate increase to approximately $48 million. The requested retail natural gas rate decrease was also revised to a decrease of approximately $8 million. The revised request is lower than the initial application and is primarily driven by certain PSCW staff adjustments, but does not include adjustments for the contested issues of incentive compensation and the customer billing system project. The revised request reflects a 10.20% return on common equity and a common equity ratio of 50.27% in WPS's regulatory capital structure. A final decision by the PSCW on the 2015 rates is expected before December 31, 2014.

2014 Rates

In December 2013, the PSCW issued a final written order for WPS, effective January 1, 2014. It authorized a net retail electric rate decrease of $12.8 million and a net retail natural gas rate increase of $4.0 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.14% in WPS's regulatory capital structure. The retail electric rate impact consisted of a rate increase, including recovery of the difference between the 2012 fuel refund and the 2013 rate increase discussed below, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. The retail natural gas rate impact consisted of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 related to the Pulliam and Weston sites. See Note 13, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its decoupling mechanism, beginning January 1, 2014.

2013 Rates

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

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

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Michigan

2015 WPS Rate Case

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

2014 MGU Rates

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

MGU Depreciation Case

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

2014 UPPCO Rates

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

Illinois

2015 Rate Cases

In February 2014, PGL and NSG filed applications with the ICC to increase retail natural gas rates $128.9 million and $7.1 million, respectively, with rates expected to be effective in early 2015. Both PGL's and NSG's requests reflect a 10.25% return on common equity. The requests reflect target common equity ratios of 50.31% for PGL and 50.41% for NSG in their respective regulatory capital structures. The proposed retail natural gas rate increases are primarily driven by increased capital investments, in particular for main replacement, a loss in revenues as a result of lower projected sales volumes, increased costs of debt and common equity, and increased operating expenses. The increase in operating expenses relates to pipeline safety and other compliance work, a general wage increase, higher depreciation costs, and higher invested capital taxes. PGL's application also removes from the proposed 2015 rates the investment and related expenses that PGL plans to recover through its new Qualifying Infrastructure Plant rider, as discussed below. PGL and NSG proposed no changes to the continued use of their decoupling mechanisms and uncollectible expense true-up mechanisms.

In October 2014, PGL and NSG filed their initial briefs and maintained their rate increase requests of $100.5 million and $6.5 million, respectively, as updated in their rebuttal and surrebutal testimony given in August and September 2014. Both PGL's and NSG's requests reflect a 10.25% return on common equity. Common equity ratios were also revised to 50.33% for PGL and 50.48% for NSG. The revised requests were primarily driven by updated capital investment amounts, including main replacement for PGL; certain updated pension and employee benefit costs based on a recent actuarial study; and adjustments for uncontested operating expenses.

The ICC staff and intervenors filed their initial briefs in October 2014. The ICC staff recommended rate increases of $71.1 million and $3.5 million for PGL and NSG, respectively, which reflected a 9.00% return on common equity for both companies. The intervenors recommended a rate increase of $45.5 million for PGL and a rate decrease of $1.0 million for NSG, which reflected a 9.15% return on common equity for both companies. Staff and intervenors both recommended a common equity ratio of 50.33% for PGL and 50.48% for NSG in their respective regulatory capital structures. A final decision on the 2015 rates is expected by the ICC in January of 2015.

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Qualifying Infrastructure Plant Rider

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

2013 Rates

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

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

2012 Decoupling

The ICC issued a final written order, effective January 21, 2012, which approved permanent decoupling mechanisms for PGL and NSG. The Illinois Attorney General and Citizens Utility Board appealed to the Court the ICC's authority to approve PGL's and NSG's decoupling mechanisms and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General's motion to make revenues collected under the permanent decoupling mechanism subject to refund and directing PGL and NSG to track amounts that would be due to customers or the companies from the permanent decoupling mechanisms. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 was uncertain, and PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Court issued an opinion that affirmed the ICC's order approving the permanent decoupling mechanism. As a result, the reserves recorded in 2012 were reversed in the first quarter of 2013. PGL's and NSG's permanent decoupling mechanism was in place for 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Court's decision. The Illinois Supreme Court granted the request in September 2013, and oral arguments were heard in September 2014. The Illinois Supreme Court has no deadline by which it must issue its decision. Decoupling amounts recorded in 2012 were fully recovered and amounts in 2013 are being refunded to customers in 2014. Decoupling amounts in 2014 will continue to be accrued, absent an adverse Illinois Supreme Court decision.

Minnesota

2014 Rates

In October 2014, the MPUC issued a final written order, which is expected to be effective in the first half of 2015. The order authorized a retail natural gas rate increase of $7.6 million. The rates reflected a 9.35% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure. The order allows for a deferral of customer billing system costs, for which the recovery will be requested in a future rate case. A decoupling mechanism with a 10% cap will remain in effect for MERC's residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, as of September 30, 2014, $2.3 million is estimated to be refunded to customers during 2015.

2011 Rates Finalized in 2013

In July 2012, the MPUC approved a final written order, effective January 1, 2013. The order authorized a retail natural gas rate increase of $11.0 million. The rates reflected a 9.70% return on common equity and a common equity ratio of 50.48% in MERC's regulatory capital structure. In addition, the order set recovery of MERC's 2011 test-year pension expense at 2010 levels. The MPUC also approved a decoupling mechanism for MERC that covers residential and small commercial and industrial customers on a three-year trial basis, effective January 1, 2013. The decoupling

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mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels. It includes an annual 10% cap based on distribution revenues approved in the rate case. Amounts recoverable from or refundable to customers are subject to this cap.

Note 23—Segments of Business

At September 30, 2014, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the regulated electric utility operations of UPPCO and WPS. In August 2014, we sold UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 4, Dispositions, for more information on the sale of UPPCO.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- The IES segment consists of a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. See Note 4, Dispositions, for information on the sale of IES's retail energy business. In addition, IES invests in energy assets with renewable attributes, primarily distributed solar assets. These renewable energy asset operations will be included in the holding company and other segment next quarter due to the sale of IES's retail energy business.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company, ITF, and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS.

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The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended September 30, 2014								
External revenues	$282.7	$342.4	$ —	$ 625.1	$537.0	$25.8	$ —	$ 1,187.9
Intersegment revenues	3.7	0.1	—	3.8	0.4	0.4	(4.6)	—
Depreciation and amortization expense	37.3	26.0	—	63.3	3.1	7.0	(0.1)	73.3
Merger transaction costs	—	—	—	—	—	2.5	—	2.5
Transaction costs related to sale of IES's retail energy business	—	—	—	—	0.9	—	—	0.9
Gain on sale of UPPCO, net of transaction costs	—	(86.3)	—	(86.3)	—	—	—	(86.3)
Gain on abandonment of IES's Winnebago Energy Center	—	—	—	—	(4.1)	—	—	(4.1)
Earnings from equity method investments	—	—	23.4	23.4	0.7	0.4	—	24.5
Miscellaneous income	1.3	2.1	—	3.4	0.3	5.6	(2.9)	6.4
Interest expense	13.4	12.0	—	25.4	0.5	15.1	(2.9)	38.1
Provision (benefit) for income taxes	(20.1)	63.0	9.2	52.1	6.9	(2.2)	—	56.8
Net income (loss) from continuing operations	(29.5)	97.1	14.2	81.8	11.1	(10.0)	—	82.9
Discontinued operations	—	—	—	—	1.1	—	—	1.1
Preferred stock dividends of subsidiary	(0.1)	(0.6)	—	(0.7)	—	—	—	(0.7)
Net income (loss) attributed to common shareholders	(29.6)	96.5	14.2	81.1	12.2	(10.0)	—	83.3

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended September 30, 2013								
External revenues	$253.0	$353.9	$ —	$ 606.9	$512.7	$10.1	$ —	$ 1,129.7
Intersegment revenues	4.2	0.1	—	4.3	0.3	0.3	(4.9)	—

Depreciation and amortization expense	35.6	25.7	—	61.3	2.9	5.5	(0.1)	69.6
Earnings from equity method investments	—	—	22.3	22.3	0.5	0.3	—	23.1
Miscellaneous income	0.4	2.8	—	3.2	6.2	5.7	(3.0)	12.1
Interest expense	12.7	8.8	—	21.5	0.5	14.1	(3.0)	33.1
Provision (benefit) for income taxes	(19.5)	25.1	8.6	14.2	6.6	(2.8)	—	18.0
Net income (loss) from continuing operations	(19.5)	40.9	13.7	35.1	12.3	(8.0)	—	39.4
Discontinued operations	—	—	—	—	(0.6)	—	—	(0.6)
Preferred stock dividends of subsidiary	(0.1)	(0.6)	—	(0.7)	—	—	—	(0.7)
Net income (loss) attributed to common shareholders	(19.6)	40.3	13.7	34.4	11.7	(8.0)	—	38.1

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Nine Months Ended September 30, 2014								
External revenues	$2,043.7	$1,004.2	$ —	$3,047.9	$2,426.6	$70.9	$ —	$5,545.4
Intersegment revenues	11.0	0.1	—	11.1	3.4	1.1	(15.6)	—
Depreciation and amortization expense	110.6	77.9	—	188.5	9.0	20.4	(0.4)	217.5
Merger transaction costs	—	—	—	—	—	8.4	—	8.4
Goodwill impairment loss	—	—	—	—	6.7	—	—	6.7
Transaction costs related to sale of IES's retail energy business	—	—	—	—	1.7	—	—	1.7
Gain on sale of UPPCO, net of transaction costs	—	(85.4)	—	(85.4)	—	—	—	(85.4)
Gain on abandonment of IES's Winnebago Energy Center	—	—	—	—	(4.1)	—	—	(4.1)
Earnings from equity method investments	—	—	68.9	68.9	1.6	0.8	—	71.3
Miscellaneous income	1.2	8.4	—	9.6	1.0	16.4	(9.6)	17.4
Interest expense	40.0	35.8	—	75.8	1.5	48.2	(9.6)	115.9
Provision (benefit) for income taxes	39.3	91.7	27.2	158.2	14.9	(18.3)	—	154.8
Net income (loss) from continuing operations	59.2	146.2	41.7	247.1	20.0	(22.9)	—	244.2
Discontinued operations	—	—	—	—	0.9	—	—	0.9
Preferred stock dividends of subsidiary	(0.3)	(2.0)	—	(2.3)	—	—	—	(2.3)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	58.9	144.2	41.7	244.8	20.9	(22.8)	—	242.9

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

September 30, 2013								
External revenues	$1,412.4	$1,012.7	$ —	$ 2,425.1	$1,470.7	$28.1	$ —	$ 3,923.9
Intersegment revenues	8.6	0.1	—	8.7	0.9	1.0	(10.6)	—
Depreciation and amortization expense	100.1	73.0	—	173.1	8.4	14.9	(0.4)	196.0
Earnings from equity method investments	—	—	66.0	66.0	1.2	1.0	—	68.2
Miscellaneous income	0.8	6.6	—	7.4	8.0	18.0	(10.1)	23.3
Interest expense	37.3	26.4	—	63.7	1.5	35.9	(10.1)	91.0
Provision (benefit) for income taxes	43.1	56.9	25.3	125.3	11.7	(12.7)	—	124.3
Net income (loss) from continuing operations	72.0	94.5	40.7	207.2	22.5	(12.0)	—	217.7
Discontinued operations	—	—	—	—	(1.2)	5.9	—	4.7
Preferred stock dividends of subsidiary	(0.4)	(1.9)	—	(2.3)	—	—	—	(2.3)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	71.6	92.6	40.7	204.9	21.3	(6.0)	—	220.2

Note 24—New Accounting Pronouncements

Recently Issued Accounting Guidance Not Yet Effective

In May 2014, the FASB issued 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

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reporting period ending March 31, 2017. The standard requires either retrospective application by restating each prior period presented in the financial statements, or modified retrospective application by recording the cumulative effect of prior reporting periods to beginning retained earnings in the year that the standard becomes effective. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

In April 2014, the FASB issued ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." The guidance raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. The guidance is effective for us for the reporting period ending March 31, 2015. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. Management early adopted this guidance in the third quarter of 2014. See Note 4, Dispositions, for more information.

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

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

In June 2014, we entered into a definitive merger agreement with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information.

In November 2014, we sold the retail energy business portion of IES. See Note 4, Dispositions, and Note 23, Segments of Business, for more information.

RESULTS OF OPERATIONS

Earnings Summary

	Three Months Ended September 30		Change in 2014 Over	Nine Months Ended September 30		Change in 2014 Over
(Millions, except per share amounts)	2014	2013	2013	2014	2013	2013
Natural gas utility operations	$(29.6)	$(19.6)	51.0 %	$58.9	$71.6	(17.7)%
Electric utility operations	96.5	40.3	139.5 %	144.2	92.6	55.7 %
Electric transmission investment	14.2	13.7	3.6 %	41.7	40.7	2.5 %
IES’s operations	12.2	11.7	4.3 %	20.9	21.3	(1.9)%
Holding company and other operations	(10.0)	(8.0)	25.0 %	(22.8)	(6.0)	280.0 %
Net income attributed to common shareholders	$83.3	$38.1	118.6 %	$242.9	$220.2	10.3 %
Basic earnings per share	$1.04	$0.48	116.7 %	$3.03	$2.78	9.0 %
Diluted earnings per share	$1.02	$0.47	117.0 %	$3.01	$2.76	9.1 %
Average shares of common stock						
Basic	80.2	79.8	0.5 %	80.2	79.3	1.1 %
Diluted	81.1	80.2	1.1 %	80.6	79.9	0.9 %

Third Quarter 2014 Compared with Third Quarter 2013

The $45.2 million increase in our earnings was driven by:

- A $51.7 million after-tax gain on the sale of UPPCO, net of transaction costs. See Note 4, Dispositions, for more information.

- A $9.9 million after-tax increase in IES's realized retail electric margins primarily due to the quarter-over-quarter positive impact of a change in pricing structure for certain electric aggregation customers.

- The $6.9 million after-tax positive impact of rate orders at the utilities.

These increases were partially offset by:

- A $9.0 million after-tax non-cash decrease in margins at IES related to derivative and inventory fair value adjustments.

- A $7.6 million net after-tax increase in operating expenses at the utilities, excluding items directly offset in margins, driven by an increase in natural gas distribution costs. The increase in natural gas distribution costs was partially offset by lower employee benefit costs.

- A $3.4 million after-tax decrease in other income at IES due to the quarter-over-quarter impact of a settlement received in 2013 related to the Seams Elimination Charge Adjustment.

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Nine Months 2014 Compared with Nine Months 2013

The $22.7 million increase in our earnings was driven by:

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

- The $40.6 million after-tax positive impact of rate orders at the utilities.

- A $20.3 million after-tax increase in natural gas utility margins due to variances related to sales volumes, net of decoupling. The increase was driven by colder than normal weather in 2014. Certain of our natural gas utilities did not have decoupling in 2014 to offset the impact of weather.

- A $5.0 million after-tax non-cash increase in margins at IES related to derivative and inventory fair value adjustments.

These increases in earnings were partially offset by:

- A $55.1 million after-tax increase in operating expenses at the utilities, excluding items directly offset in margins, driven by increases in natural gas distribution costs and electric utility maintenance. Higher depreciation and amortization expense, increased electric transmission expense, and increased costs associated with the acquisition and operation of the Fox Energy Center also contributed to the increase. The Fox Energy Center was acquired by WPS at the end of the first quarter of 2013. Partially offsetting these increases was lower employee benefit costs.

- A $16.5 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.

- A $9.9 million after-tax decrease in natural gas utility margins due to the period-over-period impact of the 2013 reversal of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 22, Regulatory Environment, for more information.

- A $6.7 million after-tax non-cash goodwill impairment loss recorded at IES in the second quarter of 2014.

- A $6.5 million after-tax increase in operating expenses at the Integrys Energy Group holding company due to transaction costs incurred in 2014 related to the proposed merger with Wisconsin Energy Corporation.

Regulated Natural Gas Utility Segment Operations

(Millions, except degree days)	Three Months Ended September 30 2014	Three Months Ended September 30 2013	Change in 2014 Over 2013	Nine Months Ended September 30 2014	Nine Months Ended September 30 2013	Change in 2014 Over 2013
Revenues	$286.4	$257.2	11.4 %	$2,054.7	$1,421.0	44.6 %
Purchased natural gas costs	115.0	93.8	22.6 %	1,218.6	685.4	77.8 %
Margins	171.4	163.4	4.9 %	836.1	735.6	13.7 %
Operating and maintenance expense	160.6	144.9	10.8 %	557.4	454.9	22.5 %
Depreciation and amortization expense	37.3	35.6	4.8 %	110.6	100.1	10.5 %
Taxes other than income taxes	11.0	9.6	14.6 %	30.8	29.0	6.2 %
Operating income (loss)	(37.5)	(26.7)	40.4 %	137.3	151.6	(9.4)%
Miscellaneous income	1.3	0.4	225.0 %	1.2	0.8	50.0 %
Interest expense	13.4	12.7	5.5 %	40.0	37.3	7.2 %
Other expense	(12.1)	(12.3)	(1.6)%	(38.8)	(36.5)	6.3 %
Income before taxes	$(49.6)	$(39.0)	27.2 %	$98.5	$115.1	(14.4)%
Retail throughput in therms						
Residential	89.3	89.2	0.1 %	1,238.9	1,108.1	11.8 %
Commercial and industrial	39.7	43.2	(8.1)%	418.0	358.9	16.5 %
Other	9.3	14.6	(36.3)%	42.9	45.4	(5.5)%
Total retail throughput in therms	138.3	147.0	(5.9)%	1,699.8	1,512.4	12.4 %
Transport throughput in therms						
Residential	18.2	16.4	11.0 %	191.0	166.8	14.5 %
Commercial and industrial	309.4	291.0	6.3 %	1,279.9	1,182.7	8.2 %
Total transport throughput in therms	327.6	307.4	6.6 %	1,470.9	1,349.5	9.0 %
Total throughput in therms	465.9	454.4	2.5 %	3,170.7	2,861.9	10.8 %
Weather						
Average actual heating degree days	185	140	32.1 %	5,216	4,589	13.7 %
Average normal heating degree days	148	142	4.2 %	4,347	4,251	2.3 %

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 30% and 56% increase in the average per-unit cost of natural gas sold during the three and nine months ended September 30, 2014, respectively, which had no impact on margins.

Third Quarter 2014 Compared with Third Quarter 2013

Margins

Regulated natural gas utility segment margins increased $8.0 million, driven by:

- An approximate $6 million net increase in margins due to sales volume variances.

  Higher sales volumes excluding the impact of weather resulted in an approximate $5 million increase in margins.

  Colder weather quarter over quarter drove an approximate $1 million increase in margins.

  Decoupling did not have a significant impact on margins quarter over quarter. See Note 22, Regulatory Environment, for more information on our decoupling mechanisms.

- An approximate $1 million net increase in margins due to rate orders, driven by rate increases at MERC and MGU, both effective January 1, 2014. See Note 22, Regulatory Environment, for more information.

- These increases were partially offset by an approximate $1 million net decrease in margins related to lower billings under certain energy efficiency programs at four of our natural gas utilities, partially offset by higher recoveries of environmental cleanup costs for NSG's and PGL's

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manufactured gas plant sites. This net decrease was offset by an equal net decrease in operating expenses, resulting in no impact on earnings. See Note 13, Commitments and Contingencies, for more information about the manufactured gas plant sites.

Operating Loss

Operating loss at the regulated natural gas utility segment increased $10.8 million. This increase was driven by an $18.8 million increase in operating expenses, partially offset by the $8.0 million increase in margins discussed above.

The increase in operating expenses was primarily due to:

- A $16.9 million increase in natural gas distribution costs, primarily at PGL. The increase in costs at PGL was driven by higher repairs and maintenance expense due to higher costs to meet new compliance requirements, including the impact on the cost to repair leaks.

- A $1.7 million net increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the accelerated natural gas main replacement program (AMRP) at PGL.

- A $1.7 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. For the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $1.4 million increase in taxes other than income taxes, driven by the Illinois invested capital tax. Because this tax is based on an entity's equity and long-term debt balances, higher equity balances at PGL and NSG resulted in an increase in taxes.

- A $1.3 million increase in consulting costs at PGL.

- A $1.2 million increase in workers compensation and injuries and damages expense. This increase was driven by both more severe injuries and increased incidents in the third quarter of 2014, primarily at PGL.

- A $1.1 million increase driven by higher information technology costs, primarily at PGL. In 2014, several information technology projects and upgrades were performed, and additional information technology services were provided.

The increase in operating expenses was partially offset by:

- A $6.0 million decrease in employee benefit costs, driven by higher discount rates assumed in 2014. The remeasurement of certain postretirement benefit plans in the first quarter of 2014 also contributed to the decrease. See Note 15, Employee Benefit Plans, for more information on this remeasurement.

- A $2.3 million decrease in energy efficiency program expenses at our natural gas utilities. For the majority of the decrease in expenses, margins decreased by an equal amount, resulting in no impact on earnings.

Nine Months 2014 Compared with Nine Months 2013

Margins

Regulated natural gas utility segment margins increased $100.5 million, driven by:

- An approximate $47 million increase in margins related to certain riders at NSG and PGL and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

  Our natural gas utilities billed approximately $18 million more to customers for energy efficiency programs at MERC, MGU, NSG, and PGL in 2014.

  NSG and PGL recovered from their customers approximately $16 million more for environmental cleanup costs at their former manufactured gas plant sites due to higher recovery rates driven by an increase in remediation costs, net of insurance settlements received, and the impact of higher sales volumes. See Note 13, Commitments and Contingencies, for more information about the manufactured gas plant sites.

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

- An approximate $33 million net increase in margins due to rate orders. See Note 22, Regulatory Environment, for more information.

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The rate increases at NSG and PGL, effective June 27, 2013, and updated effective January 1, 2014, had an approximate $30 million positive impact on margins.

The rate increase at MGU, effective January 1, 2014, resulted in an approximate $3 million positive impact on margins.

The interim rate increase at MERC, effective January 1, 2014, had an approximate $3 million positive impact on margins.

These increases were partially offset by the approximate $3 million negative impact of WPS's rate order, effective January 1, 2014. Although the PSCW approved a net rate increase, it was driven by the recovery of the 2012 decoupling under-collections to be recovered from customers in 2014, which has no impact on margins. The remaining decrease was partially offset by the positive impact of rate design changes. See Note 22, Regulatory Environment, for more information.

- An approximate $17 million net increase in margins due to sales volume variances and our decoupling mechanisms.

The combined effect of the change in weather period over period, the impact of higher weather-normalized volumes, and the impact of our decoupling mechanisms increased margins approximately $34 million. In 2014, margins at the natural gas utilities were positively impacted by colder than normal weather, net of decoupling impacts at MERC, NSG, and PGL. Effective January 1, 2014, MGU and WPS no longer have decoupling mechanisms in place. During the first quarter of 2014, MERC reached its maximum accrued refund to customers under the annual 10% cap provision of its decoupling mechanism. In 2013, decoupling mechanisms were in place for all the natural gas utilities. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 22, Regulatory Environment, for more information on our decoupling mechanisms.

Margins were negatively impacted period-over-period by approximately $17 million due to a reversal in 2013 of reserves established in 2012 against PGL and NSG regulatory assets related to decoupling. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 22, Regulatory Environment, for more information.

Operating Income

Operating income at the regulated natural gas utility segment decreased $14.3 million. This decrease was driven by a $114.8 million increase in operating expenses, partially offset by the $100.5 million increase in margins discussed above.

The increase in operating expenses was primarily due to:

- A $35.9 million increase in natural gas distribution costs, primarily at PGL. The increase in costs at PGL was driven by higher repairs and maintenance expense due to higher costs to meet new compliance requirements, including the impact on the cost to repair leaks.

- A $17.2 million increase in energy efficiency program expenses at our natural gas utilities. For the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $16.7 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. For the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $16.0 million increase in bad debt expense, driven by higher natural gas costs in 2014, an increase in sales volumes, and rate increases. The majority of the increase in bad debt expense related to PGL and NSG and had no impact on earnings since it was offset by higher rates through a rider mechanism, resulting in higher margins.

- A $10.5 million net increase in depreciation and amortization expense. This increase was driven by a $3.4 million reduction in expense in 2013 at MERC related to a new depreciation study approved by the MPUC on July 29, 2013, retroactive to January 1, 2012. The increase was also driven by a $2.5 million reduction in expense at MGU in 2013. In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010. See Note 22, Regulatory Environment, for more information. Continued investment in property and equipment, primarily the AMRP at PGL, also contributed to the increase in expense.

- A $4.1 million increase in consulting costs, primarily related to the AMRP at PGL.

- A $3.9 million increase in asset usage charges from IBS, driven by new software for both natural gas management and work asset management that was placed in service during the third quarter of 2013.

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

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- A $3.6 million increase driven by higher information technology costs, primarily at PGL. In 2014, several information technology projects and upgrades were performed, and additional information technology services were provided.

- A $3.1 million increase in workers compensation and injuries and damages expense. This increase was driven by both more severe injuries and increased incidents in 2014, primarily at PGL.

- A $1.8 million increase in taxes other than income taxes, primarily driven by the Illinois invested capital tax. Because this tax is based on an entity's equity and long-term debt balances, higher equity balances at PGL and NSG resulted in an increase in taxes.

The increase in operating expenses was partially offset by a $4.6 million decrease in employee benefit costs, primarily due to:

- An $11.0 million decrease in pension costs, driven by higher discount rates assumed in 2014.

- This decrease in pension costs was partially offset by:

A $3.4 million increase in stock-based compensation expense, driven by the period-over-period increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in our stock price.

The $3.2 million negative period-over-period impact of the deferral of employee benefit costs in 2013 and the related amortization in 2014. In 2013, WPS deferred certain increases in pension and other employee benefit costs as a result of its 2013 rate order with the PSCW. WPS began amortizing this regulatory asset in 2014.

Other Expense

Other expense at the regulated natural gas utilities increased $2.3 million. Interest expense on long-term debt increased, driven by higher average long-term debt outstanding in 2014.

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Regulated Electric Utility Segment Operations

(Millions, except degree days)	Three Months Ended September 30 2014	Three Months Ended September 30 2013	Change in 2014 Over 2013	Nine Months Ended September 30 2014	Nine Months Ended September 30 2013	Change in 2014 Over 2013
Revenues	$342.5	$354.0	(3.2)%	$1,004.3	$1,012.8	(0.8)%
Fuel and purchased power costs	117.4	133.6	(12.1)%	366.9	408.1	(10.1)%
Margins	225.1	220.4	2.1%	637.4	604.7	5.4%
Operating and maintenance expense	104.5	110.6	(5.5)%	343.1	323.5	6.1%
Depreciation and amortization expense	26.0	25.7	1.2%	77.9	73.0	6.7%
Taxes other than income taxes	10.9	12.1	(9.9)%	36.5	37.0	(1.4)%
Gain on sale of UPPCO, net of transaction costs	(86.3)	—	N/A	(85.4)	—	N/A
Operating income	170.0	72.0	136.1%	265.3	171.2	55.0%
Miscellaneous income	2.1	2.8	(25.0)%	8.4	6.6	27.3%
Interest expense	12.0	8.8	36.4%	35.8	26.4	35.6%
Other expense	(9.9)	(6.0)	65.0%	(27.4)	(19.8)	38.4%
Income before taxes	$160.1	$66.0	142.6%	$237.9	$151.4	57.1%
Sales in kilowatt-hours						
Residential	750.9	837.8	(10.4)%	2,336.4	2,354.2	(0.8)%
Commercial and industrial	2,145.2	2,242.8	(4.4)%	6,312.8	6,418.5	(1.6)%
Wholesale	839.5	1,092.4	(23.2)%	2,246.0	3,277.1	(31.5)%
Other	7.7	8.0	(3.8)%	25.9	26.4	(1.9)%
Total sales in kilowatt-hours	3,743.3	4,181.0	(10.5)%	10,921.1	12,076.2	(9.6)%
Weather						
WPS:						
Actual heating degree days	243	216	12.5%	5,778	5,126	12.7%
Normal heating degree days	210	216	(2.8)%	4,831	4,837	(0.1)%
Actual cooling degree days	224	396	(43.4)%	333	527	(36.8)%
Normal cooling degree days	364	361	0.8%	505	498	1.4%
UPPCO:						
Actual heating degree days	241	473	(49.0)%	6,639	6,189	7.3%
Normal heating degree days	398	404	(1.5)%	5,765	5,770	(0.1)%
Actual cooling degree days	68	194	(64.9)%	122	230	(47.0)%
Normal cooling degree days	181	176	2.8%	238	231	3.0%

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.

Third Quarter 2014 Compared with Third Quarter 2013

Margins

Regulated electric utility segment margins increased $4.7 million.

- Margins increased approximately $11 million related to WPS and UPPCO rate orders, effective January 1, 2014. See Note 22, Regulatory Environment, for more information.

Excluding the impacts from fuel and purchased power costs, the WPS 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.

UPPCO's retail electric rate increase resulted in an approximate $2 million increase in margins.

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Margins at WPS were negatively impacted approximately $9 million related to fuel and purchased power-related costs that are not included in the fuel rule recovery mechanism. During 2013, customer rates included recovery of estimated purchased power costs from the Fox Energy Center that exceeded actual purchased power costs because the acquisition of this plant in March 2014 was not anticipated in the 2013 rate case. This resulted in a negative quarter-over-quarter impact on margins in 2014, which was partially offset by decreased costs in 2014 associated with fly ash disposal.

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

- Margins decreased approximately $7 million related to sales volume variances. The decrease was primarily driven by lower sales volumes related to cooler than normal weather in the third quarter of 2014 and the sale of UPPCO in August 2014. These decreases were partially offset by the impact of the termination of our decoupling mechanisms, effective January 1, 2014. See Note 4, Dispositions, for more information on the sale of UPPCO. See Note 22, Regulatory Environment, for more information on our decoupling mechanisms.

Operating Income

Operating income at the regulated electric utility segment increased $98.0 million. The increase was primarily driven by an $86.3 million net gain on the sale of UPPCO. See Note 4, Dispositions, for more information. The remaining increase in operating income was driven by a $7.0 million decrease in operating expenses and the $4.7 million increase in margins discussed above.

The decrease in operating expenses was driven by:

- A $6.1 million net decrease in employee benefit costs, including the impact of the prior year deferral of some of these costs.

Employee benefit costs decreased $9.7 million in the third quarter of 2014. This decrease was partially driven by the remeasurement of certain other postretirement benefit plan obligations. See Note 15, Employee Benefit Plans, for more information. Continued funding of our pension plan and higher discount rates assumed in 2014 for both our pension and postretirement plans also contributed to the overall decrease in employee benefit costs.

This decrease was partially offset by the quarter-over-quarter impact of a deferral of certain increases in WPS employee benefit costs in 2013, recorded in accordance with its PSCW rate order, and the related amortization in 2014. Together, these changes increased employee benefit costs by $3.6 million at WPS.

- A $1.8 million decrease due to the quarter-over-quarter impact of WPS's 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of a power purchase agreement. However, WPS did receive PSCW approval to defer ownership costs above or below its power purchase agreement expenses in 2013.

Other Expense

Other expense increased $3.9 million. The primary driver was an increase in interest expense on long-term debt, driven by higher average outstanding long-term debt at WPS in the third quarter of 2014.

Nine Months 2014 Compared with Nine Months 2013

Margins

Regulated electric utility segment margins increased $32.7 million, driven by:

- An approximate $37 million increase in margins related to WPS and UPPCO rate orders, effective January 1, 2014. See Note 22, Regulatory Environment, for more information.

Excluding the impacts from fuel and purchased power costs, the WPS PSCW rate order resulted in an approximate $56 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.

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

Margins at WPS were negatively impacted approximately $16 million related to fuel and purchased power-related cost that are not included in the fuel rule recovery mechanism. During 2013, customer rates included recovery of estimated purchased power costs from

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the Fox Energy Center that exceeded actual purchased power costs because the acquisition of this plant in March 2014 was not anticipated in the 2013 rate case. This resulted in a negative period-over-period impact on margins in 2014, which was partially offset by decreased costs in 2014 associated with fly ash disposal.

Margins were further decreased approximately $9 million related to fuel and purchased power cost under-collections at WPS in 2014, compared with over-collections in 2013. Under the fuel rule, WPS can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

- An approximate $5 million increase in WPS's wholesale margins driven by higher prices. Wholesale prices increased primarily due to the pass-through of increased generation costs to these customers, partially a result of the purchase of the Fox Energy Center in 2013.

- A partially offsetting decrease in margins of approximately $10 million related to sales volume variances. The decrease was primarily driven by our sale of UPPCO at the end of August 2014. See Note 4, Dispositions, for more information. Margins from our large commercial and industrial customers also decreased, driven by lower use per customer in 2014. These decreases were partially offset by the impact of the termination of our decoupling mechanisms, effective January 1, 2014. See Note 22, Regulatory Environment, for more information. Our decoupling mechanism did not cover large commercial and industrial customers.

Operating Income

Operating income at the regulated electric utility segment increased $94.1 million. The increase was primarily driven by an $85.4 million net gain on the sale of UPPCO. See Note 4, Dispositions, for more information. The remaining increase in operating income was due to the $32.7 million increase in margins discussed above, partially offset by a $24.0 million increase in operating expenses.

The increase in operating expenses was driven by:

- A $22.9 million increase in maintenance expense, primarily due to planned major outages in 2014 at the Pulliam plant, Fox Energy Center, and Weston 4, as well as maintenance at certain other WPS generation plants. These increases were partially offset by the period-over-period impact of maintenance expenses associated with the Weston 3 planned major outage in 2013.

- A $4.9 million increase in depreciation and amortization expense, mainly due to the acquisition of the Fox Energy Center at the end of the first quarter of 2013. In addition, we completed the installation of scrubbers at the Columbia plant in April 2014.

- A $4.9 million increase in various costs associated with the acquisition and operation of the Fox Energy Center. Included in this amount is the amortization of a regulatory asset related to the fee paid for the early termination of the Fox Energy Center power purchase agreement. Recovery of the amortization was included in the new rates.

- A $4.7 million increase in electric transmission expense.

- A $2.1 million increase in amortization of the deferral of previously recorded production tax credits related to the WPS Crane Creek wind project.

These increases were partially offset by:

- A $9.4 million net decrease in employee benefit costs, including the impact of the prior year deferral of some of these costs. Employee benefit costs other than stock-based compensation (discussed below) decreased $22.0 million in 2014. This decrease was partially driven by the remeasurement of certain other postretirement benefit plans. See Note 15, Employee Benefit Plans, for more information. Continued funding of our pension plan and higher discount rates assumed in 2014 for both our pension and postretirement plans also contributed to the overall decrease in employee benefit costs. This decrease was partially offset by:

  Higher stock-based compensation expense of $1.7 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 our stock price.

  The period-over-period impact of a deferral of certain increases in WPS employee benefit costs in 2013, recorded in accordance with its PSCW rate order, and the related amortization in 2014. Together, these changes increased employee benefit costs by $10.9 million at WPS.

- A $5.1 million decrease due to the period-over-period impact of WPS's 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of a power purchase agreement. However, WPS did receive PSCW approval to defer ownership costs above or below its power purchase agreement expenses in 2013.

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Other Expense

Other expense increased $7.6 million. The primary driver was an $11.6 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt at WPS in 2014. An increase in AFUDC of $2.8 million at WPS, largely due to the construction of the ReACT™ emission control technology at the Weston 3 plant, partially offset the increase in interest expense.

Electric Transmission Investment Segment Operations

	Three Months Ended September 30		Change in 2014 Over	Nine Months Ended September 30		Change in 2014 Over
(Millions)	2014	2013	2013	2014	2013	2013
Earnings from equity method investments	$23.4	$22.3	4.9 %	$68.9	$66.0	4.4 %

Third Quarter 2014 Compared with Third Quarter 2013

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $1.1 million in the third quarter of 2014. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

Nine Months 2014 Compared with Nine Months 2013

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $2.9 million in 2014. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

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IES Segment Operations

On November 1, 2014, we sold IES's retail energy business to Exelon Generation Company, LLC. See Note 4, Dispositions, for more information.

(Millions, except natural gas sales volumes)	Three Months Ended September 30 2014	2013	Change in 2014 Over 2013	Nine Months Ended September 30 2014	2013	Change in 2014 Over 2013
Revenues	$537.4	$513.0	4.8 %	$2,430.0	$1,471.6	65.1 %
Cost of sales	491.7	469.3	4.8 %	2,283.3	1,343.7	69.9 %
Margins	45.7	43.7	4.6 %	146.7	127.9	14.7 %
Margin Detail						
Realized retail electric margins	32.4	15.9	103.8 %	70.0	66.4	5.4 %
Realized wholesale electric margins (1)	(0.1)	—	N/A	—	0.4	(100.0)%
Realized renewable energy asset margins	5.7	5.0	14.0 %	12.2	12.5	(2.4)%
Fair value accounting adjustments	0.1	17.4	(99.4)%	21.0	15.4	36.4 %
Electric and renewable energy asset margins	38.1	38.3	(0.5)%	103.2	94.7	9.0 %
Realized retail natural gas margins (2)	4.4	4.4	— %	35.9	27.9	28.7 %
Realized wholesale natural gas margins (1)	(0.1)	0.1	N/A	(0.2)	0.2	N/A
Lower-of-cost-or-market inventory adjustments	(0.4)	(0.9)	(55.6)%	0.5	1.4	(64.3)%
Fair value accounting adjustments	3.7	1.8	105.6 %	7.3	3.7	97.3 %
Natural gas margins	7.6	5.4	40.7 %	43.5	33.2	31.0 %
Operating and maintenance expense	26.0	27.5	(5.5)%	94.6	90.4	4.6 %
Depreciation and amortization expense	3.1	2.9	6.9 %	9.0	8.4	7.1 %
Taxes other than income taxes	2.3	0.6	283.3 %	5.0	2.6	92.3 %
Goodwill impairment loss	—	—	N/A	6.7	—	N/A
Transaction costs related to sale of IES's retail energy business	0.9	—	N/A	1.7	—	N/A
Gain on abandonment of IES's Winnebago Energy Center	(4.1)	—	N/A	(4.1)	—	N/A
Operating income	17.5	12.7	37.8 %	33.8	26.5	27.5 %
Earnings from equity method investments	0.7	0.5	40.0 %	1.6	1.2	33.3 %
Miscellaneous income	0.3	6.2	(95.2)%	1.0	8.0	(87.5)%
Interest expense	0.5	0.5	— %	1.5	1.5	— %
Other income	0.5	6.2	(91.9)%	1.1	7.7	(85.7)%
Income before taxes	$18.0	$18.9	(4.8)%	$34.9	$34.2	2.0 %
Physically settled volumes						
Retail electric sales volumes in kwh	5,946.3	6,291.0	(5.5)%	18,051.9	15,447.3	16.9 %
Wholesale assets and distributed solar electric sales volumes in kwh	14.6	17.4	(16.1)%	46.5	51.1	(9.0)%
Retail natural gas sales volumes in bcf	38.0	34.8	9.2 %	170.2	122.6	38.8 %

kwh — kilowatt-hours
bcf — billion cubic feet

(1) Realized wholesale activity relates to remaining contracts for which offsetting positions were entered into.

(2) Amounts include negative margins related to the amortization of the net amount paid for customer and related supply contracts in connection with acquisitions. The three and nine months ended September 30, 2014, include negative margins of $1.0 million and $5.1 million, respectively. The three and nine months ended September 30, 2013, include negative margins of $1.5 million and $2.8 million, respectively.

Third Quarter 2014 Compared with Third Quarter 2013

Revenues

IES's revenues increased $24.4 million, primarily driven by higher retail natural gas sales volumes. Higher average electric commodity prices also contributed to the increase in revenues.

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Margins

IES’s margins increased $2.0 million. Significant items contributing to the change in margins were as follows:

Realized retail electric margins

Realized retail electric margins increased $16.5 million. The quarter-over-quarter positive impact was driven by a change in pricing structure for certain electric aggregation customers. In 2013, IES was unable to fully recover fixed costs as the usage for these customers was lower than anticipated. Also contributing to the increased margins were improved per-unit margins.

Fair value accounting adjustments

Derivative accounting rules impact IES’s margins. Fair value adjustments drove a $17.3 million decrease in electric margins and a $1.9 million increase in natural gas margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with electric and natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income

IES’s operating income increased $4.8 million. The increase was driven by a $2.8 million decrease in operating expenses and the $2.0 million increase in margins discussed above. The decrease in operating expenses was driven by:

- A $4.1 million gain on the abandonment of the Winnebago Energy Center. See Note 4, Dispositions, for more information.

- A $2.8 million decrease in payroll and employee benefit expenses, primarily related to decreases in stock-based compensation and deferred compensation expense. The decrease in stock-based compensation expense was driven by an adjustment to the estimated forfeiture rate in the third quarter of 2014 to reflect the sale of IES's retail energy business. The decrease in deferred compensation expense was driven by the quarter-over-quarter change in the fair value of amounts owed to plan participants under deferred compensation plans.

- A $2.3 million decrease due to IES settling its $6.6 million liability for contingent consideration related to the acquisition of Compass Energy Services (Compass) for $4.3 million in the third quarter of 2014.

These decreases in operating expenses were partially offset by:

- A $3.8 million increase in service fees paid to utility companies related to IES's direct mass market business.

- A $1.7 million increase in taxes other than income taxes, primarily related to the write-off of tax receivables that IES no longer expects to collect.

Other Income

IES's other income decreased $5.7 million. The decrease was due to the quarter-over-quarter impact of a $5.7 million settlement received in 2013 related to the Seams Elimination Charge Adjustment (SECA).

Nine Months 2014 Compared with Nine Months 2013

Revenues

IES’s revenues increased $958.4 million. The increase was driven by higher retail sales volumes, primarily related to growth in IES's existing electric and natural gas markets as well as the Compass acquisition in May 2013. Higher average electric commodity prices and increased usage in 2014 related to the colder weather also contributed to the higher revenues.

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Margins

IES's margins increased $18.8 million. Significant items contributing to the change in margins were as follows:

Electric and Renewable Energy Asset Margins

Realized retail electric margins

Realized retail electric margins increased $3.6 million. The increase was driven by growth in existing markets, as well as the period-over-period positive impact of a change in pricing structure for certain electric aggregation customers. Partially offsetting these increases were increased costs related to the colder weather in the first quarter of 2014. Sales volumes for fixed-price full requirements customers increased significantly due to the colder weather, requiring IES to purchase power at high market prices to meet this unexpected demand.

Fair value accounting adjustments

Derivative accounting rules impact IES's margins. Fair value adjustments caused a $5.6 million increase in electric margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins increased $8.0 million. The increase was primarily driven by colder weather period over period. Higher sales volumes, primarily related to the Compass acquisition in May 2013 and growth in IES's existing markets, also contributed to the increase in margins. Realized retail natural gas margins include the amortization of customer and supply contracts related to the acquisition of Compass.

Fair value accounting adjustments

Derivative accounting rules impact IES's margins. Fair value adjustments caused a $3.6 million increase in natural gas margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income

IES's operating income increased $7.3 million. The increase was driven by the $18.8 million increase in margins discussed above, partially offset by an $11.5 million increase in operating expenses. The increase in operating expenses was driven by:

- A $6.7 million goodwill impairment loss recorded in the second quarter of 2014. See Note 9, Goodwill and Other Intangible Assets, for more information.

- A $6.4 million increase in service fees paid to utility companies related to IES's direct mass market business.

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A $2.4 million increase in taxes other than income taxes, primarily related to the write-off of tax receivables that IES no longer expects to collect.

- A $1.7 million increase due to transaction costs incurred in 2014 related to the sale of IES's retail energy business. See Note 4, Dispositions, for more information.

These increases in operating expenses were partially offset by:

- A $4.1 million gain on the abandonment of the Winnebago Energy Center. See Note 4, Dispositions, for more information.

- A $2.3 million decrease due to IES settling its $6.6 million liability for contingent consideration related to the acquisition of Compass for $4.3 million in the third quarter of 2014.

Other Income

IES's other income decreased $6.6 million. The decrease was driven by the period-over-period impact of a $5.7 million settlement received in 2013 related to the SECA.

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Holding Company and Other Segment Operations

(Millions)	Three Months Ended September 30 2014	2013	Change in 2014 Over 2013	Nine Months Ended September 30 2014	2013	Change in 2014 Over 2013
Operating loss	$(3.1)	$(2.7)	14.8 %	$(10.2)	$(7.8)	30.8 %
Other expense	(9.1)	(8.1)	12.3 %	(31.0)	(16.9)	83.4 %
Loss before taxes	$(12.2)	$(10.8)	13.0 %	$(41.2)	$(24.7)	66.8 %

Third Quarter 2014 Compared with Third Quarter 2013

Operating Loss

Operating loss at the holding company and other segment increased $0.4 million. The increase was mainly driven by $2.5 million of transaction costs related to the proposed merger with Wisconsin Energy Corporation, partially offset by a $2.0 million decrease in operating losses at ITF.

Other Expense

Other expense at the holding company and other segment increased $1.0 million. The increase was primarily due to a $0.9 million increase in interest expense on long-term debt, driven by the issuance of $400.0 million of Junior Subordinated Notes during August 2013.

Nine Months 2014 Compared with Nine Months 2013

Operating Loss

Operating loss at the holding company and other segment increased $2.4 million. The increase was mainly driven by $8.4 million of transaction costs related to the proposed merger with Wisconsin Energy Corporation, partially offset by a $4.5 million decrease in operating losses at ITF.

Other Expense

Other expense at the holding company and other segment increased $14.1 million. The increase was primarily due to a $12.8 million increase in interest expense on long-term debt, driven by the issuance of $400.0 million of Junior Subordinated Notes during August 2013. Also contributing to the increase was the $3.2 million period-over-period negative impact of excise tax credits recorded at ITF in 2013 as a result of the American Taxpayer Relief Act of 2012. These excise tax credits were not available in 2014.

Provision for Income Taxes

	Three Months Ended September 30 2014	2013	Nine Months Ended September 30 2014	2013
Effective tax rate	40.7 %	31.4 %	38.8 %	36.3 %

Third Quarter 2014 Compared with Third Quarter 2013

Our effective tax rate increased in the third quarter of 2014. This increase was primarily due to a $3.7 million decrease in our provision for income taxes in the third quarter of 2013 as a result of the reversal of a regulatory liability. This amount was related to deferred income taxes that had been recorded in prior years as a result of scheduled income tax rate changes in Illinois. We recorded the reversal based on the income tax treatment included in the 2013 final rate order for PGL and NSG.

Nine Months 2014 Compared with Nine Months 2013

Our effective tax rate increased in 2014. This increase was primarily driven by the tax treatment of IES's $6.7 million goodwill impairment loss recorded in the second quarter of 2014. This amount is not deductible for income tax purposes.

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Discontinued Operations

(Millions)	Three Months Ended September 30 2014	2013	Change in 2014 Over 2013	Nine Months Ended September 30 2014	2013	Change in 2014 Over 2013
Discontinued operations, net of tax	$1.1	$(0.6)	N/A	$0.9	$4.7	(80.9)%

Third Quarter 2014 Compared with Third Quarter 2013

Earnings from discontinued operations, net of tax, increased $1.7 million in the third quarter of 2014. In 2014, IES settled the earn-out agreement related to the sale of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse). As a result, IES recognized after-tax earnings from discontinued operations of $1.2 million related to Beaver Falls and Syracuse during the third quarter of 2014. See Note 4, Dispositions, for more information.

Nine Months 2014 Compared with Nine Months 2013

Earnings from discontinued operations, net of tax, decreased $3.8 million in 2014. In 2013, we remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. We reduced the provision for income taxes related to this remeasurement, of which $5.9 million was reported as discontinued operations. Partially offsetting this decrease in earnings was the recognition by IES of after-tax earnings from discontinued operations of $1.2 million related to Beaver Falls and Syracuse in 2014. As discussed above, IES settled the earn-out agreement related to the sale of Beaver Falls and Syracuse in the third quarter of 2014. See Note 4, Dispositions, for more information. In addition, the operating results of IES's Combined Locks Energy Center also improved by $1.1 million during 2014.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

During the nine months ended September 30, 2014, net cash provided by operating activities was $617.9 million, compared with $512.2 million during the same period in 2013. The $105.7 million increase in net cash provided by operating activities was driven by:

- A $1,785.1 million increase in cash collections from customers, mainly due to rate increases at the regulated utilities, higher commodity prices, and the colder than normal weather in 2014.
- The positive period-over-period impact of a $50.0 million payment in 2013 for WPS's early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.
- A $22.4 million increase in cash from customer prepayments and credit balances. In 2013, cash received in relation to amounts billed was lower because customer prepayments had grown during an unusually warm 2012.

- A $3.9 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. This refund was partially offset by cash paid for income taxes related to the sale of UPPCO.

- A $2.1 million increase in cash driven by lower collateral requirements in 2014 compared with 2013. Collateral requirements are based on forward natural gas and electricity prices and forward positions with counterparties.

These increases in cash were partially offset by:

- A $1,523.0 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, the colder than normal weather, and for energy costs associated with operating the Fox Energy Center, which WPS acquired at the end of the first quarter of 2013.

- A $176.9 million decrease in cash related to increased operating and maintenance costs in 2014. The decrease was driven by increases in natural gas distribution costs, electric utility maintenance, and operating costs associated with the purchase of the Fox Energy Center in 2013.

- A $30.4 million increase in contributions to pension and other postretirement benefit plans.

- A $27.4 million increase in cash paid for interest, primarily driven by higher average outstanding long-term debt in 2014 as compared with 2013.

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Investing Cash Flows

During the nine months ended September 30, 2014, net cash used for investing activities was $388.7 million, compared with $819.8 million during the same period in 2013. The $431.1 million decrease in net cash used for investing activities was primarily due to:

- The positive period-over-period impact of cash used to purchase two businesses in 2013. WPS purchased Fox Energy Company LLC for $391.6 million, and IES purchased Compass Energy Services for $12.4 million in 2013. See Note 3, Acquisitions, for more information.

- The receipt of proceeds of $332.2 million in 2014 related to the sale of UPPCO. See Note 4, Dispositions, for more information.

These decreases in cash used were partially offset by:

- A $116.2 million increase in cash used for other capital expenditures (discussed below).

- A $113.0 million increase in cash used due to the required funding of the rabbi trust for deferred compensation and certain nonqualified pension plans. The proposed merger with Wisconsin Energy Corporation qualified as a potential change in control event under the rabbi trust agreement, which required the funding of the rabbi trust. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information about the merger.

- The period-over-period negative impact of the receipt of a $69.0 million Section 1603 Grant for the Crane Creek wind project in 2013.

Capital Expenditures

Capital expenditures by business segment for the nine months ended September 30 were as follows:

Reportable Segment (millions)	2014	2013	Change in 2014 Over 2013
Natural gas utility	$303.1	$268.9	$34.2
Electric utility	194.8	551.3	(356.5)
IES	18.2	8.8	9.4
Holding company and other	74.8	37.3	37.5
Integrys Energy Group consolidated	$590.9	$866.3	$(275.4)

The increase in capital expenditures at the natural gas utility segment in 2014 compared with 2013 was primarily due to work on the accelerated natural gas main replacement program at PGL. Capital expenditures related to distribution, transmission, and natural gas storage also contributed to the increase.

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

The increase in capital expenditures at IES in 2014 compared with 2013 was primarily due to an increase in solar projects.

Finally, capital expenditures at the holding company and other segment increased in 2014 compared with 2013, primarily due to increased expenditures for software projects and office leasehold improvements.

Financing Cash Flows

During the nine months ended September 30, 2014, net cash used for financing activities was $235.4 million, compared with net cash provided by financing activities of $306.3 million during the same period in 2013. The $541.7 million period-over-period change was driven by:

- A $637.0 million net decrease in cash due to a $724.0 million decrease in the issuance of long-term debt, which was partially offset by an $87.0 million decrease in the repayment of long-term debt.

- A $200.0 million decrease in borrowings under WPS's term credit facility, which were used in 2013 to partially finance the acquisition of Fox Energy Company LLC.

- A $43.1 million increase in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. We began purchasing shares of our common stock on the open market starting in February 2014 as well as during a short period during the first quarter of 2013.

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- An $18.5 million decrease in cash received from stock option exercises.

These decreases in cash used were partially offset by $360.9 million of higher net borrowings of commercial paper in 2014.

Significant Financing Activities

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

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

Under the merger agreement with Wisconsin Energy Corporation, we can no longer issue shares of our common stock.

For information on short-term debt, see Note 10, Short-Term Debt and Lines of Credit.

For information on long-term debt, see Note 11, Long-Term Debt.

Credit Ratings

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

Credit Ratings	Standard & Poor's	Moody's
Integrys Energy Group		
Issuer credit rating	A-	N/A
Senior unsecured debt	BBB+	A3
Commercial paper	A-2	P-2
Junior subordinated notes	BBB	Baa1
WPS		
Issuer credit rating	A-	A1
First mortgage bonds	N/A	Aa2
Senior secured debt	A	Aa2
Preferred stock	BBB	A3
Commercial paper	A-2	P-1
PGL		
Issuer credit rating	A-	A2
Senior secured debt	N/A	Aa3
Commercial paper	A-2	P-1
NSG		
Issuer credit rating	A-	A2

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

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

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

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Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of September 30, 2014, including those of our subsidiaries:

		Payments Due By Period			
(Millions)	Total Amounts Committed	2014	2015 to 2016	2017 to 2018	2019 and Later Years
Long-term debt principal and interest payments [1]	$ 7,162.0	$36.2	$507.7	$383.9	$6,234.2
Operating lease obligations	78.9	1.7	10.6	12.2	54.4
Energy and transportation purchase obligations [2]	1,832.7	92.4	582.6	358.2	799.5
Purchase orders [3]	1,043.8	778.3	235.6	21.9	8.0
Pension and other postretirement funding obligations [4]	43.8	15.6	28.2	—	—
Capital contributions to equity method investment	3.4	3.4	—	—	—
Uncertain tax positions	0.7	0.7	—	—	—
Total contractual cash obligations	$ 10,165.3	$928.3	$1,364.7	$776.2	$7,096.1

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

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

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2016. The proposed merger with Wisconsin Energy Corporation qualified as a potential change in control event under the rabbi trust agreement and triggered the full funding of our deferred compensation obligation and our obligation for certain nonqualified pension plans. As a result, the funding requirements related to certain nonqualified pension plan obligations were reduced by $2.0 million in 2014 and $8.3 million in 2015.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $557.9 million at September 30, 2014, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 13, Commitments and Contingencies, for more information about environmental liabilities. The table also does not reflect estimated future payments for the September 30, 2014 liability of $1.9 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 12, Income Taxes, for more information about unrecognized tax benefits.

Capital Requirements

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

(Millions)	2014	2015	2016	Total
Natural Gas Utility				

Distribution, transmission, and underground storage facilities	$507	$478	$481	$1,466
Other projects	29	34	23	86
Electric Utility				
Distribution, transmission, and energy supply operations projects	133	137	131	401
Environmental projects (1)	150	135	105	390
Other projects	7	11	158	176
IES				
Renewable energy and other projects (2)	60	40	40	140
Holding Company and Other				
Corporate or shared services software and infrastructure projects	68	31	40	139
Compressed natural gas fueling stations	27	44	45	116
Total capital expenditures	$981	$910	$1,023	$2,914

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

(2) See Note 4, Dispositions, for more information on the sale of IES's retail energy business.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $49 million from 2014 through 2016.

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

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management strategies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage our liquidity and capital resource needs. We plan to meet our capital requirements for the period 2014 through 2016 primarily through internally generated funds (net of forecasted dividend payments), dividends from our subsidiaries, and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

Under an existing shelf registration statement, we may issue debt, equity, certain types of hybrid securities, and other financial instruments with amounts, prices, and terms to be determined at the time of future offerings.

WPS currently has a shelf registration statement under which it may issue up to $50.0 million of additional senior debt securities. Amounts, prices, and terms will be determined at the time of future offerings.

As a result of the sale of IES's retail energy business on November 1, 2014, we plan to reduce the size of our existing revolving credit facilities over the next six months as contingent obligations are fully transferred to Exelon Generation Company, LLC.

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

Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. Our regulated utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 17, Common Equity, for more information on dividend restrictions.

Other Future Considerations

Presque Isle System Support Resource (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 when 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 compensates Wisconsin Electric Power by allocating the SSR costs associated with the operation of the Presque Isle units to regulated and nonregulated load serving entities, including WPS, based on load ratio share within the ATC footprint. In 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. In August 2014, MISO submitted a revised rate schedule to the FERC based on a new load-shed analysis, which reduced the allocated SSR costs for WPS from the original estimate of approximately $9 million annually to $0.3 million annually. Later in August 2014, the MPSC requested a rehearing of the FERC's decision to change the allocation methodology, which the PSCW is protesting.

In April 2013, the PSCW ordered that SSR costs for WPS retail customers should be deferred until December 31, 2015. At that time, the PSCW will determine the appropriate ratemaking treatment. As of September 30, 2014, there were no material SSR costs for WPS retail customers deferred for future recovery. SSR costs for Michigan customers are being recovered through the Power Supply Cost Recovery mechanism. SSR costs for WPS's wholesale customers are being recovered through formula rates.

MISO Transmission Owner Return on Equity Complaint

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting, among other things, to reduce the base return on equity (ROE) used by MISO transmission owners, including ATC, to 9.15%. ATC's current authorized ROE is 12.2%. In October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 12, 2013. However, the FERC denied all other aspects of the complaint, including that the use of capital structures that include more than 50% common equity is unjust and unreasonable. If the case does not settle, the FERC expects to issue a decision by August 31, 2016.

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

The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues will be guided by the New England transmission decision. Any change to ATC's 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, financial impact, and nature of any FERC actions related to this complaint.

Wisconsin Fuel Rule Under-collection "Cap"

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

Decoupling

In 2012, the Illinois Attorney General and Citizens Utility Board appealed the ICC's authority to approve PGL's and NSG's permanent decoupling mechanism. As a result, revenues collected under this mechanism were potentially subject to refund. In 2012, PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Illinois Appellate Court affirmed the ICC's authority to approve the permanent decoupling mechanism. Therefore, the reserves recorded in 2012 were reversed in the first quarter of 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Court's decision. The Illinois Supreme Court granted the request in September 2013, and oral arguments were heard in September 2014. The Illinois Supreme Court has no deadline by which it must issue its decision. Decoupling amounts recorded in 2012 were fully recovered and amounts in 2013 are being refunded to customers in 2014. Decoupling amounts in 2014 will continue to be accrued, absent an adverse Illinois Supreme Court decision.

See Note 22, Regulatory Environment, for more information on all of our subsidiaries' decoupling mechanisms.

Climate Change

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

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

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

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

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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, except as follows:

Goodwill Impairment

In June 2014, IES performed an interim goodwill impairment analysis. This interim analysis was triggered by the announcement of the plan to divest of IES's retail energy business. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss of $6.7 million in the second quarter of 2014. See Note 9, Goodwill and Other Intangible Assets, for more information about this goodwill impairment.

In addition to IES's interim goodwill impairment analysis, we completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2014. No impairments were recorded as a result of our annual impairment tests. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. The fair value was calculated using an equal weighting of the income approach and the market approach.

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

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

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

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

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

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

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

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

As a result of the November 1, 2014 sale of IES's retail energy business, we are no longer exposed to any material commodity price risk at IES.

Other than the above-mentioned change, our market risks have not changed materially from the market risks reported in our 2013 Annual Report on Form 10-K.

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

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

The Amo Action and Illinois Actions allege, among other things, that members of our board breached their fiduciary duties in connection with the proposed transaction, and that the merger agreement involves an unfair price, was the product of an inadequate sales process, and contains unreasonable deal protection devices that purportedly preclude competing offers. The complaints further variously allege that we, Wisconsin Energy, and/or its acquisition subsidiaries aided and abetted the purported breaches of fiduciary duty. The plaintiffs in these lawsuits seek, among other things, (i) a declaration that the merger agreement was entered into in breach of our directors' fiduciary duties, (ii) an injunction enjoining our board from consummating the merger, (iii) an order directing our board to exercise their duties to obtain a transaction which is in the best interests of our shareholders, (iv) an order granting the class members any benefits allegedly improperly received by the defendants, (v) a rescission of the merger or damages, in the event that it is consummated, and/or (vi) an order directing additional disclosure regarding the merger.

The Inman Action generally asserts similar claims on behalf of the purported class and derivatively on behalf of us and, in addition, alleges that the registration statement omits material information.

The Steiner and Collison Actions generally allege that the members of our board breached their fiduciary duties by conducting an inadequate sales process that resulted in an unfair price and by filing a materially deficient registration statement. The Steiner and Collison Actions further allege that Wisconsin Energy aided and abetted those breaches of fiduciary duty. The plaintiffs in the Steiner and Collison Actions, seek, among other things, to enjoin the proposed transaction or an award of damages in the event the merger is consummated. In addition, the Collison complaint alleges that the members of our board were unjustly enriched at the expense of us and seeks a court order directing our board members to disgorge all benefits or compensation obtained as a result of their purported breaches of fiduciary duty.

The Tri-State Action seeks to enjoin the proposed transaction and alleges that we, our board, Wisconsin Energy, and Mr. Klappa (the Wisconsin Energy Chief Executive Officer) violated Sections 14(a) and 20(a) of the 1934 Securities Exchange Act and Rule 14a-9 promulgated thereunder. It alleges, among other things, that the registration statement misrepresented or omitted material facts, including material information about the allegedly unfair and conflicted sales process, the inadequate consideration offered in the proposed transaction, and our actual intrinsic value.

On August 6, 2014, we, our board, and Wisconsin Energy filed a motion to dismiss or stay the Illinois Actions, in deference to the Wisconsin Actions. On August 11, 2014, we, our board, and Wisconsin Energy filed motions to dismiss the Amo Action. Also on August 11, 2014, the plaintiffs in the Wisconsin Actions filed a letter with the courts in which those actions are pending, requesting that the Wisconsin Actions be stayed pending resolution of the Illinois

Actions. We, our board, and Wisconsin Energy filed a letter opposing that request on August 12, 2014.

On August 12, 2014, the plaintiffs in the Brown County Actions voluntarily dismissed their suits without prejudice. On August 18, 2014, the plaintiff in the Amo Action moved the Wisconsin court to stay his action in favor of the Illinois Actions. Following a hearing on September 4, 2014, the Wisconsin court denied the plaintiff's motion to stay the Amo Action.

On August 27, 2014, the plaintiff in the Taxman action filed a motion for leave to amend his complaint seeking to add allegations that the defendants breached their fiduciary duty of candor by filing a materially deficient registration statement.

On September 30, 2014, the Illinois court dismissed the Illinois Actions in favor of the Amo Action and Inman Action.

On October 3, 2014, the plaintiff in the Amo Action, joined by plaintiffs from the Brown County Actions, filed an amended class action complaint adding allegations that the defendants breached their fiduciary duties by filing a materially deficient registration statement. On October 6, 2014, we, our board, and Wisconsin Energy filed a motion for a protective order staying discovery pending a decision on their motions to dismiss in the Amo Action. On October 7, 2014, the plaintiff in the Amo Action, joined by plaintiffs from the Brown County Actions, filed a motion for limited expedited discovery.

On October 8, 2014, we, our board, and Wisconsin Energy filed motions to dismiss the Steiner and Collison Actions, in deference to the Wisconsin Actions. On October 15, 2014, the Collison Action was consolidated with the Steiner Action.

On October 17, 2014, the Inman Action was consolidated with the Amo Action. On October 21, 2014, the Inman plaintiff in the consolidated Amo Action filed a motion for expedited discovery and a preliminary injunction.

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We believe the claims asserted in each lawsuit have no merit and intend to defend the actions vigorously.

See Note 13, Commitments and Contingencies, for information on other material legal proceedings and matters.

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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 27, 2014, other than the following. These risks relate to the proposed merger with Wisconsin Energy Corporation (Wisconsin Energy).

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

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

The merger agreement limits our ability to pursue alternatives to the merger, which could discourage a potential acquirer from making an alternative transaction proposal and, in certain circumstances, could require us to pay to Wisconsin Energy a significant termination fee.

Under the merger agreement, we are restricted, subject to limited exceptions, from pursuing or entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, we are restricted from, among other things, soliciting, initiating, knowingly encouraging, inducing or knowingly facilitating a competing acquisition proposal from any person. Our board of directors is limited in its ability to change its recommendation with respect to the merger-related proposal. We or Wisconsin Energy may terminate the merger agreement and enter into an agreement with respect to a superior offer only if specified conditions have been satisfied, including compliance with the non-solicitation provisions of the merger agreement, the expiration of certain waiting periods during which the other party may propose changes to the merger agreement so the superior offer is no longer a superior offer and the payment of the required termination fee. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of us from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger, or might result in a potential acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable. As a result of these restrictions, we may not be able to enter into an agreement with respect to a more favorable alternative transaction without incurring potentially significant liability to Wisconsin Energy.

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

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others who deal with us to seek to change existing business relationships with us. Employee retention and recruitment may be particularly challenging prior to completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company.

The pursuit of the merger and the preparation for the integration of us and Wisconsin Energy may place a significant burden on management and internal resources. Any significant diversion of management attention away from ongoing business and any difficulties encountered in the transition and integration process could affect our financial results and/or the financial results of the combined company.

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

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

We and Wisconsin Energy entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, accretion to the combined company's earnings per share in the first full calendar year following completion of the merger. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether our business and the business of Wisconsin Energy can be integrated in an efficient and effective manner, whether U.S. federal and state public utility, antitrust and other regulatory authorities whose approval is required to complete the merger impose conditions on the completion of the merger, which may have an adverse effect on the combined company, including its ability to achieve the anticipated benefits of the merger, general market and economic conditions, general competitive factors in the marketplace and higher than expected costs required to achieve the anticipated benefits of the merger.

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

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

In connection with the merger, purported shareholders of us have filed putative stockholder class action lawsuits against us and our directors and Wisconsin Energy. Among other remedies, the plaintiffs seek to enjoin the merger. In addition, one of the conditions to the closing of the merger is that no law or judgment issued by any court of competent jurisdiction shall be in effect that, and no suit, action or other proceeding shall be pending before any governmental entity in which such governmental entity seeks to impose any legal restraint that, makes illegal or prohibits the consummation of the merger. Consequently, if one of the plaintiffs is successful in obtaining an injunction prohibiting us or Wisconsin Energy from consummating the merger on the agreed-upon terms, then the injunction may prevent the merger from being completed within the expected timeframe, or at all. Furthermore, if the defendants are not able to resolve these lawsuits, the lawsuits could result in substantial costs to us and Wisconsin Energy, including any costs associated with the indemnification of directors. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition or results of operations.

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

Completion of the merger is contingent upon, among other things, the receipt of all required regulatory approvals, which, in the case of Wisconsin Energy, consist of filings with and approvals of the New York Stock Exchange (NYSE), notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the Federal Communications Commission (FCC), notice to and approval of the PSCW, the ICC and the MPSC, and, if required or advisable, the MPUC and, in our case, consist of filings with and approvals of the NYSE, notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the FCC, notice to and approval of the ICC and the MPSC, and, to the extent required, notice to and approval of the MPUC. We can provide no assurance that all required regulatory authorizations, approvals or consents will be obtained or that the authorizations, approvals or consents will not contain terms, conditions or restrictions that would be detrimental to the combined company after completion of the merger.

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

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

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

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

- having to pay certain significant costs relating to the merger without receiving the benefits of the merger, including, in certain circumstances, a termination fee of $175 million;

- the attention of our management may have been diverted to the merger rather than to our own operations and the pursuit of other opportunities that could have been beneficial to us;

- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;

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- we will have been subject to certain restrictions on the conduct of our business which may have prevented us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger was pending;

- our share price may decline to the extent that the current market price reflects an assumption by the market that the merger will be completed; and

- we may be subject to litigation related to any failure to complete the merger.

In addition, ten purported class action and/or derivative lawsuits have been filed against us, members of our board of directors and
Wisconsin Energy, seeking, among other things, an injunction prohibiting the consummation of the merger. While we believe these lawsuits are without merit, we cannot make any assurances as to the outcome of these lawsuits.

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

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

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

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

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

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

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. See Note 17, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends, as well as dividend restrictions under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy).

Issuer Purchases of Equity Securities

The following table provides a summary of common stock purchases for the three months ended September 30, 2014:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
07/01/14 – 07/31/14 *	9,293	$69.49	—	—
08/01/14 – 08/31/14 *	23,578	66.40	—	—
09/01/14 – 09/30/14 *	195,220	67.73	—	—
Total	228,091	$67.66	—	—

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

Under the merger agreement with Wisconsin Energy, we can no longer issue shares of our common stock.

Item 6. Exhibits

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

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant, Integrys Energy Group, Inc., has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

INTEGRYS ENERGY GROUP, INC.
(Registrant)

Date: November 5, 2014

/s/ Linda M. Kallas
Linda M. Kallas
Vice President and Controller

(Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS ENERGY GROUP
EXHIBIT INDEX TO FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2014

Exhibit No.	Description
2	Stock Purchase Agreement, dated as of July 29, 2014, between Integrys Energy Group, Inc. and Exelon Generation Company, LLC., as amended on October 31, 2014.
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 Integrys Energy Group, Inc.
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 Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended September 30, 2014, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Statements of Comprehensive Income, (iii) the Condensed Consolidated Balance Sheets, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity information.