INTEGRYS ENERGY GROUP, INC.
Form 10-Q
November 07, 2013
Table of Contents

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, 2013

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) 130 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,
79,807,435 shares outstanding at
November 4, 2013

Table of Contents

INTEGRYS ENERGY GROUP, INC.
QUARTERLY REPORT ON FORM 10-Q
For the Quarter Ended September 30, 2013
TABLE OF CONTENTS

Table of Contents

Acronyms Used in this Quarterly Report on Form 10-Q

AFUDC	Allowance for Funds Used During Construction
AMRP	Accelerated Natural Gas Main Replacement Program
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC (doing business as Trillium CNG)
LIFO	Last-in, First-out
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
OCI	Other Comprehensive Income
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

Table of Contents

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 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, 2012, 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 our regulated businesses;
- 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;
- Other 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;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries' liquidity and financing efforts;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;
- The ability to retain market-based rate authority;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The impact of unplanned facility outages;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer use, customer growth, and our ability to adequately forecast energy use for our customers;
- Potential business strategies, including mergers, acquisitions, and construction or disposition of assets or businesses, which cannot be assured to be completed timely or within budgets;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
-

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;

- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The ability to use tax credit and loss carryforwards;
- The financial performance of ATC and its corresponding contribution to our earnings;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file with the SEC.

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

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions, except per share data)	2013	2012	2013	2012
Utility revenues	$606.9	$582.3	$2,425.1	$2,116.9
Nonregulated revenues	522.8	345.4	1,498.8	898.3
Total revenues	1,129.7	927.7	3,923.9	3,015.2
Utility cost of fuel, natural gas, and purchased power	222.8	228.2	1,083.9	926.4
Nonregulated cost of sales	475.3	264.0	1,360.0	730.0
Operating and maintenance expense	282.3	240.3	866.1	748.6
Depreciation and amortization expense	69.6	62.9	196.0	187.6
Taxes other than income taxes	24.4	23.8	76.4	73.9
Operating income	55.3	108.5	341.5	348.7
Earnings from equity method investments	23.1	22.2	68.2	65.5
Miscellaneous income	12.1	3.1	23.3	7.2
Interest expense	33.1	29.9	91.0	90.0
Other income (expense)	2.1	(4.6)	0.5	(17.3)
Income before taxes	57.4	103.9	342.0	331.4
Provision for income taxes	18.0	29.6	124.3	106.6
Net income from continuing operations	39.4	74.3	217.7	224.8
Discontinued operations, net of tax	(0.6)	(8.0)	4.7	(9.2)
Net income	38.8	66.3	222.4	215.6
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Net income attributed to common shareholders	$38.1	$65.7	$220.2	$213.4
Average shares of common stock				
Basic	79.8	78.5	79.3	78.5
Diluted	80.2	79.3	79.9	79.3
Earnings per common share (basic)				
Net income from continuing operations	$0.49	$0.94	$2.72	$2.84
Discontinued operations, net of tax	(0.01)	(0.10)	0.06	(0.12)
Earnings per common share (basic)	$0.48	$0.84	$2.78	$2.72
Earnings per common share (diluted)				
Net income from continuing operations	$0.48	$0.93	$2.70	$2.81
Discontinued operations, net of tax	(0.01)	(0.10)	0.06	(0.12)

Earnings per common share (diluted)	$0.47	$0.83	$2.76	$2.69
Dividends per common share declared	$0.68	$0.68	$2.04	$2.04

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

2

Table of Contents

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2013	2012	2013	2012
Net income	$38.8	$66.3	$222.4	$215.6
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net gains (losses) arising during period, net of tax of $ – million, $0.1 million, $ – million, and $(0.1) million, respectively	—	0.1	0.7	(0.1)
Reclassification of net losses to net income, net of tax of $0.2 million, $1.0 million, $1.7 million, and $2.6 million, respectively	0.3	1.6	2.7	4.1
Cash flow hedges, net	0.3	1.7	3.4	4.0
Defined benefit plans				
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.4 million, $0.2 million, $1.2 million, and $0.7 million, respectively	0.6	0.4	1.8	1.1
Other comprehensive income, net of tax	0.9	2.1	5.2	5.1
Comprehensive income	39.7	68.4	227.6	220.7
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Comprehensive income attributed to common shareholders	$39.0	$67.8	$225.4	$218.5

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

Table of Contents

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)	September 30	December 31
(Millions)	2013	2012
Assets		
Cash and cash equivalents	$26.1	$ 27.4
Collateral on deposit	61.1	41.0
Accounts receivable and accrued unbilled revenues, net of reserves of $45.3 and $43.5, respectively	625.3	796.8
Inventories	341.7	271.9
Assets from risk management activities	154.9	145.4
Regulatory assets	101.7	110.8
Assets held for sale	0.7	10.1
Deferred income taxes	38.4	64.3
Prepaid taxes	141.8	152.8
Other current assets	30.0	38.6
Current assets	1,521.7	1,659.1
Property, plant, and equipment, net of accumulated depreciation of $3,307.9 and $3,114.7, respectively	6,198.8	5,501.9
Regulatory assets	1,784.6	1,813.8
Assets from risk management activities	58.1	45.3
Equity method investments	534.5	512.2
Goodwill	662.1	658.3
Other long-term assets	161.5	136.8
Total assets	$10,921.3	$ 10,327.4
Liabilities and Equity		
Short-term debt	$388.0	$ 482.4
Current portion of long-term debt	276.5	313.5
Accounts payable	475.4	457.7
Liabilities from risk management activities	157.5	181.9
Accrued taxes	41.2	83.0
Regulatory liabilities	56.1	65.6
Liabilities held for sale	—	0.2
Other current liabilities	237.9	229.0
Current liabilities	1,632.6	1,813.3
Long-term debt	2,506.2	1,931.7
Deferred income taxes	1,320.4	1,203.8
Deferred investment tax credits	48.4	49.3
Regulatory liabilities	390.4	370.5
Environmental remediation liabilities	613.6	651.5
Pension and other postretirement benefit obligations	573.0	625.2
Liabilities from risk management activities	59.6	58.4
Asset retirement obligations	426.8	411.2
Other long-term liabilities	138.8	135.7
Long-term liabilities	6,077.2	5,437.3

Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 79,757,715 shares issued; 79,289,748 shares outstanding	79.8	78.3
Additional paid-in capital	2,648.1	2,574.6
Retained earnings	489.8	431.5
Accumulated other comprehensive loss	(35.7)	(40.9)
Shares in deferred compensation trust	(22.7)	(17.7)
Total common shareholders' equity	3,159.3	3,025.8
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	1.1	(0.1)
Total liabilities and equity	$10,921.3	$ 10,327.4

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

4

Table of Contents

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

	Nine Months Ended September 30	
(Millions)	2013	2012
Operating Activities		
Net income	$222.4	$215.6
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	(4.7)	9.2
Depreciation and amortization expense	196.0	187.6
Recoveries and refunds of regulatory assets and liabilities	35.2	12.6
Net unrealized gains on energy contracts	(18.8)	(42.8)
Bad debt expense	22.2	19.3
Pension and other postretirement expense	47.4	46.7
Pension and other postretirement contributions	(65.0)	(247.8)
Deferred income taxes and investment tax credits	123.4	86.3
Equity income, net of dividends	(14.1)	(13.4)
Termination of tolling agreement with Fox Energy Company LLC	(50.0)	—
Other	33.4	32.8
Changes in working capital		
Collateral on deposit	(20.1)	(1.1)
Accounts receivable and accrued unbilled revenues	80.4	232.6
Inventories	(70.1)	(20.9)
Other current assets	(7.6)	66.8
Accounts payable	21.9	(45.0)
Other current liabilities	(21.0)	5.8
Net cash provided by operating activities	510.9	544.3
Investing Activities		
Capital expenditures	(474.7)	(437.8)
Proceeds from the sale or disposal of assets	4.6	8.2
Capital contributions to equity method investments	(10.2)	(24.0)
Acquisition of Fox Energy Company LLC	(391.6)	—
Acquisitions at Integrys Energy Services	(12.4)	—
Grant received related to Crane Creek Wind Project	69.0	—
Other	(6.1)	4.8
Net cash used for investing activities	(821.4)	(448.8)
Financing Activities		
Short-term debt, net	(294.4)	107.0
Borrowing on term credit facility	200.0	—
Issuance of long-term debt	724.0	28.0
Repayment of long-term debt	(187.0)	(28.2)
Proceeds from stock option exercises	38.5	54.9
Shares purchased for stock-based compensation	(2.0)	(85.1)
Payment of dividends		
Preferred stock of subsidiary	(2.3)	(2.3)
Common stock	(151.6)	(159.0)
	(5.7)	(27.9)

Payments made on derivative contracts related to divestitures classified as financing activities		
Other	(13.2)	0.5
Net cash provided by (used for) financing activities	306.3	(112.1)
Change in cash and cash equivalents – continuing operations	(4.2)	(16.6)
Change in cash and cash equivalents – discontinued operations		
Net cash provided by operating activities	1.3	6.7
Net cash provided by (used for) investing activities	1.6	(0.1)
Net change in cash and cash equivalents	(1.3)	(10.0)
Cash and cash equivalents at beginning of period	27.4	28.1
Cash and cash equivalents at end of period	$26.1	$18.1

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

5

INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
September 30, 2013

NOTE 1 — FINANCIAL INFORMATION

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, 2012. Financial results for an interim period may not give a true indication of results for the year.

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

NOTE 2 — CASH AND CASH EQUIVALENTS

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

The following is a supplemental disclosure to our statements of cash flows:

	Nine Months Ended September 30	
(Millions)	2013	2012
Cash paid for interest	$60.7	$60.0
Cash received for income taxes	(2.6)	(45.7)

Cash received for income taxes decreased $43.1 million, primarily driven by a federal income tax refund received in 2012 for a net operating loss incurred in 2010 that was carried back to a prior year. The 2010 net operating loss was driven by bonus depreciation.

Significant noncash transactions were:

	Nine Months Ended September 30	
(Millions)	2013	2012
Construction costs funded through accounts payable	$98.4	$78.8
Equity issued for stock-based compensation plans	26.5	—
Equity issued for reinvested dividends	9.1	—
Contingent consideration and payables related to the acquisition of Compass Energy Services *	7.9	—

* See Note 4, "Acquisitions," for more information on the contingent consideration.

Table of Contents

NOTE 3 — RISK MANAGEMENT ACTIVITIES

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

		September 30, 2013	
(Millions)	Balance Sheet Presentation *	Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$2.2	$5.4
Natural gas contracts	Long-term	0.5	0.6
Financial transmission rights (FTRs)	Current	3.4	0.4
Petroleum product contracts	Current	—	0.2
Coal contracts	Current	—	2.6
Coal contracts	Long-term	1.5	0.1
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	48.9	37.6
Natural gas contracts	Long-term	24.6	14.6
Electric contracts	Current	100.4	111.3
Electric contracts	Long-term	31.5	44.3
	Current	154.9	157.5
	Long-term	58.1	59.6
Total		$213.0	$217.1

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

		December 31, 2012	
(Millions)	Balance Sheet Presentation *	Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$2.5	$14.0
Natural gas contracts	Long-term	0.9	0.8
FTRs	Current	2.1	0.1
Petroleum product contracts	Current	0.2	—
Coal contracts	Current	0.3	4.7
Coal contracts	Long-term	2.2	4.3
Cash flow hedges			
Natural gas contracts	Current	—	0.4
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	51.7	48.5
Natural gas contracts	Long-term	11.5	7.6
Electric contracts	Current	88.6	114.2
Electric contracts	Long-term	30.7	45.7

	Current	145.4	181.9
	Long-term	45.3	58.4
Total		$190.7	$240.3

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

7

Table of Contents

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

	September 30, 2013		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$5.9	$2.3	$3.6
Nonregulated segments	205.4	119.2	86.2
Total	211.3	121.5	89.8
Derivative assets not subject to master netting or similar arrangements	1.7		1.7
Total risk management assets	$213.0		$91.5
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$6.6	$2.7	$3.9
Nonregulated segments	207.1	145.2	61.9
Total	213.7	147.9	65.8
Derivative liabilities not subject to master netting or similar arrangements	3.4		3.4
Total risk management liabilities	$217.1		$69.2

	December 31, 2012		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$5.7	$3.0	$2.7
Nonregulated segments	182.5	145.4	37.1
Total	188.2	148.4	39.8
Derivative assets not subject to master netting or similar arrangements	2.5		2.5
Total risk management assets	$190.7		$42.3
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$15.3	$3.8	$11.5
Nonregulated segments	215.4	159.8	55.6
Total	230.7	163.6	67.1
Derivative liabilities not subject to master netting or similar arrangements	9.6		9.6
Total risk management liabilities	$240.3		$76.7

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

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

(Millions)	September 30, 2013	December 31, 2012
Cash collateral provided to others:		
Related to contracts under master netting or similar arrangements	$60.0	$ 39.9
Other	1.1	1.1
Cash collateral received from others related to contracts under master netting or similar arrangements *	—	0.2

* Reflected in other current liabilities on the balance sheets.

Table of Contents

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, 2013	December 31, 2012
Integrys Energy Services	$83.3	$ 108.9
Utility segments	5.2	14.0

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, 2013	December 31, 2012
Collateral that would have been required:		
Integrys Energy Services	$185.4	$ 173.8
Utility segments	2.2	10.1
Collateral already satisfied:		
Integrys Energy Services — Letters of credit	4.5	3.2
Collateral remaining:		
Integrys Energy Services	180.9	170.6
Utility segments	2.2	10.1

Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, coal purchase contracts, financial derivative contracts (futures, options, and swaps), and FTRs used to manage electric transmission congestion costs. Both the electric and natural gas utility segments use futures, options, and swaps to manage the risks associated with the market price volatility of natural gas supply costs, and the costs of gasoline and diesel fuel used by utility vehicles. The electric utility segment also uses oil futures and options to manage price risk related to coal transportation.

The utilities had the following notional volumes of outstanding derivative contracts:

	September 30, 2013			December 31, 2012		
	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (millions of therms)	1,104.1	1.7	N/A	1,072.6	0.1	N/A
FTRs (millions of kilowatt-hours)	N/A	N/A	5,858.1	N/A	N/A	4,057.2
Petroleum products (barrels)	76,822.0	9,000.0	N/A	62,811.0	—	N/A
Coal (millions of tons)	5.1	N/A	N/A	5.1	N/A	N/A

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

		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	Financial Statement Presentation	2013	2012	2013	2012
Natural gas	Balance Sheet — Regulatory assets (current)	$(0.5)	$10.2	$6.9	$22.9

Natural gas	Balance Sheet — Regulatory assets (long-term)	1.8	3.8	1.6	7.7
Natural gas	Balance Sheet — Regulatory liabilities (current)	(0.4)	(3.4)	(0.2)	(2.9)
Natural gas	Balance Sheet — Regulatory liabilities (long-term)	—	0.8	(0.3)	1.3
Natural gas	Income Statement — Utility cost of fuel, natural gas, and purchased power	—	0.1	—	0.2
Natural gas	Income Statement — Operating and maintenance expense	(0.1)	0.1	(0.2)	0.1
FTRs	Balance Sheet — Regulatory assets (current)	0.8	—	—	(0.4)
FTRs	Balance Sheet — Regulatory liabilities (current)	(0.2)	(0.2)	(0.3)	0.5
Petroleum	Balance Sheet — Regulatory assets (current)	0.1	0.2	—	0.1
Petroleum	Balance Sheet — Regulatory liabilities (current)	—	0.1	—	0.1
Petroleum	Income Statement — Operating and maintenance expense	(0.2)	0.1	(0.2)	0.1
Coal	Balance Sheet — Regulatory assets (current)	(0.6)	0.7	2.1	(2.5)
Coal	Balance Sheet — Regulatory assets (long-term)	0.2	(0.1)	4.2	0.1
Coal	Balance Sheet — Regulatory liabilities (current)	—	—	(0.3)	—
Coal	Balance Sheet — Regulatory liabilities (long-term)	1.5	—	(0.7)	—

9

Table of Contents

Nonregulated Segments

Nonhedge Derivatives

Integrys Energy Services enters into derivative contracts such as futures, forwards, options, and swaps that are used to manage commodity price risk primarily associated with retail electric and natural gas customer contracts.

Integrys Energy Services had the following notional volumes of outstanding derivative contracts:

	September 30, 2013		December 31, 2012	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity contracts				
Natural gas (therms)	1,108.5	1,011.8	782.0	679.0
Electric (kilowatt-hours)	50,956.9	32,059.6	54,127.6	31,809.6
Foreign exchange contracts (Canadian dollars)	—	—	0.4	0.4

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

		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	Income Statement Presentation	2013	2012	2013	2012
Natural gas	Nonregulated revenue	$(21.1)	$(4.4)	$16.1	$7.0
Natural gas	Nonregulated cost of sales	25.0	—	(9.5)	—
Natural gas	Nonregulated revenue (reclassified from accumulated OCI) *	—	(0.1)	(0.2)	(1.6)
Electric	Nonregulated revenue	36.0	49.1	22.4	(10.5)
Electric	Nonregulated cost of sales	(6.6)	—	2.1	—
Electric	Nonregulated revenue (reclassified from accumulated OCI) *	(0.2)	(1.9)	(3.2)	(3.3)
Total		$33.1	$42.7	$27.7	$(8.4)

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated in prior periods.

In the next 12 months, insignificant losses related to discontinued cash flow hedges of natural gas and electric contracts are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative customer contracts.

NOTE 4 — 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, and will be around $11 million. This acquisition will not be material to us.

Acquisition of Compass Energy Services

In May 2013, Integrys Energy Services acquired all of the equity interests of Compass Energy Services, Inc. and its wholly-owned subsidiary (Compass), a nonregulated retail natural gas business supplying commercial and industrial customers primarily in the Mid Atlantic and Ohio regions. This transaction expands Integrys Energy Services' retail natural gas presence and provides a solid foundation for future growth in these regions.

This acquisition was not material to us. Integrys Energy Services paid $12.4 million to acquire this business. Under the terms of the purchase agreement, the former owners of Compass will be eligible to receive additional cash consideration of up to $8.0 million (but no less than $3.0 million), based upon the financial performance of Compass over the next five years. Integrys Energy Services recorded liabilities of $7.7 million related to this contingent consideration.

Table of Contents

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	
Inventories	$0.7
Assets from risk management activities (current)	15.1
Other current assets	1.1
Assets from risk management activities (long-term)	9.3
Other long-term assets	6.1
Total assets acquired	$32.3
Liabilities assumed	
Liabilities from risk management activities (current)	$8.3
Other current liabilities	0.5
Liabilities from risk management activities (long-term)	3.4
Total liabilities assumed	$12.2

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 expected to run primarily on natural gas. This plant gives WPS a more balanced mix of owned electric generation, including coal, natural gas, hydroelectric, wind, and other renewable sources. In giving its approval for the purchase, the PSCW stated that the purchase price was reasonable and will benefit ratepayers.

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

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

(1) Relates to the electric utility segment.

(2) Intangible assets recorded for contractual services agreements. See Note 8, "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. In the current rate case, WPS proposed amortizing the regulatory asset over a nine-year period, beginning January 1, 2014. This has not been challenged, and WPS expects PSCW approval in the final decision in this rate case.

The purchase was financed with a combination of short-term debt and cash provided by operations. WPS intends to replace the short-term debt in the fourth quarter of 2013 with long-term financing.

WPS received regulatory approval to defer incremental costs associated with the purchase of the facility. Operating costs for the Fox Energy Center subsequent to the date of acquisition are included in our income statement. Due to regulatory deferral, these costs had no impact on net income. 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.

Table of Contents

NOTE 5 — DISCONTINUED OPERATIONS

Discontinued Operations at Holding Company and Other Segment

During the nine months ended September 30, 2013, and 2012, we recorded $5.9 million and $1.8 million of after-tax gains, respectively, 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.

Discontinued Operations at Integrys Energy Services Segment

Potential Sale of Combined Locks Energy Center

Integrys Energy Services is currently pursuing the sale of the Combined Locks Energy Center (Combined Locks), a natural gas-fired co-generation facility located in Wisconsin, as part of its long-term energy asset strategy. An agreement to sell Combined Locks is expected to be entered into by the end of 2013.

The carrying values of the major classes of assets related to Combined Locks classified as held for sale on the balance sheets were as follows:

(Millions)	September 30, 2013	December 31, 2012
Inventories	$0.5	$0.5
Property, plant, and equipment, net of accumulated depreciation of $ – and $0.5 million, respectively	0.2	2.0
Total assets	$0.7	$2.5

A summary of the components of discontinued operations related to Combined Locks recorded on the income statements follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2013	2012	2013	2012
Nonregulated revenues	$(0.1)	$—	$(0.1)	$0.3
Nonregulated cost of sales	(0.1)	(0.1)	(0.2)	(0.5)
Operating and maintenance expense	(0.8)	(0.1)	(2.0)	(0.3)
Depreciation and amortization expense	—	(0.1)	—	(0.2)
Taxes other than income taxes	—	—	—	(0.1)
Loss before taxes	(1.0)	(0.3)	(2.3)	(0.8)
Benefit for income taxes	0.4	0.2	0.9	0.3
Discontinued operations, net of tax	$(0.6)	$(0.1)	$(1.4)	$(0.5)

Sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC

In March 2013, WPS Empire State, Inc, a subsidiary of Integrys Energy Services, sold all of the membership interests of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse), both of which own natural gas-fired generation plants located in the state of New York. The cash proceeds from the sale were $1.6 million. The sale agreement also included a potential annual payment to Integrys Energy Services for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). Integrys Energy Services recorded a pre-tax impairment loss in operating and maintenance expense of $4.0 million ($2.4 million after tax) related to Beaver Falls and Syracuse during the third quarter of 2012 when the assets and liabilities were classified as held for sale.

The carrying values of the major classes of assets and liabilities related to Beaver Falls and Syracuse classified as held for sale on the balance sheet were as follows:

(Millions)	As of December 31, 2012
Inventories	$1.8
Property, plant, and equipment	5.7
Other long-term assets	0.1
Total assets	$7.6
Total liabilities – other current liabilities	$0.2

In conjunction with the sale, the buyer assumed certain derivative contracts from WPS Empire State, Inc. Integrys Energy Services maintained these contracts to secure physical capacity for both its retail electric business obligations, as well as sales to external counterparties. The carrying value of the derivative contract liabilities assumed by the buyer was $6.8 million at closing. As of September 30, 2013, Integrys Energy Services is in the process of novating the external capacity contracts to the buyer.

Table of Contents

A summary of the components of discontinued operations related to Beaver Falls and Syracuse recorded on the income statements were as follows:

(Millions)	Three Months Ended September 30, 2012	Nine Months Ended September 30 2013	2012
Nonregulated revenues	$1.2	$1.2	$1.5
Nonregulated cost of sales	(0.7)	(0.9)	(1.6)
Operating and maintenance expense	(4.6)	0.4*	(5.7)
Depreciation and amortization expense	(0.2)	—	(0.6)
Taxes other than income taxes	—	(0.3)	(1.1)
Income (loss) before taxes	(4.3)	0.4	(7.5)
(Provision) benefit for income taxes	1.7	(0.2)	3.0
Discontinued operations, net of tax	$(2.6)	$0.2	$(4.5)

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

The sale of Beaver Falls and Syracuse may generate immaterial cash flows from a four-year annual earn-out payment. Integrys Energy Services will also continue to purchase capacity from these facilities to satisfy certain capacity obligations, but is in the process of novating a majority of these obligations to the buyer, and will continue to settle certain forward financial natural gas swaps under contracts that existed at the time of sale. Both of these transactions will generate cash flows, of which the majority will expire upon novation or within two years of the sale, and are not considered significant to the overall operations of Beaver Falls and Syracuse. Integrys Energy Services does not have the ability to significantly influence the operating or financial policies of Beaver Falls and Syracuse and also does not have significant continuing involvement in the operations of Beaver Falls and Syracuse. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Beaver Falls and Syracuse.

Sale of WPS Westwood Generation, LLC

In November 2012, Sunbury Holdings, LLC, a subsidiary of Integrys Energy Services, sold all of the membership interests of WPS Westwood Generation, LLC (Westwood), a waste coal generation plant located in Pennsylvania. The cash proceeds related to the sale were $2.6 million. Integrys Energy Services also received a $4.0 million note receivable from the buyer with a seven and one-half year term. Integrys Energy Services recorded a pre-tax impairment loss in operating and maintenance expense of $8.4 million ($5.0 million after tax) related to Westwood during the third quarter of 2012 when the assets and liabilities were classified as held for sale.

A summary of the components of discontinued operations related to Westwood recorded on the income statements were as follows:

(Millions)	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Nonregulated revenues	$2.2	$8.2
Nonregulated cost of sales	(1.2)	(3.6)
Operating and maintenance expense	(9.3)	(12.9)
Depreciation and amortization expense	(0.3)	(1.0)
Taxes other than income taxes	(0.1)	(0.2)
Interest expense	(0.1)	(0.4)
Loss before taxes	(8.8)	(9.9)

Benefit for income taxes	3.5	3.9
Discontinued operations, net of tax	$(5.3)	$(6.0)

Integrys Energy Services will receive interest income for seven and one-half years from the sale date related to the note receivable from the buyer. Integrys Energy Services does not have the ability to significantly influence the operating or financial policies of Westwood and also does not have significant continuing involvement in the operations of Westwood. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Westwood.

NOTE 6 — 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, 2013. ATC is a for-profit, transmission-only company regulated by FERC.

Table of Contents

The following table shows changes to our investment in ATC.

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2013	2012	2013	2012
Balance at the beginning of period	$492.2	$456.4	$476.6	$439.4
Add: Earnings from equity method investment	22.3	21.7	66.0	63.8
Add: Capital contributions	3.4	8.5	10.2	17.0
Less: Dividends received	17.8	17.3	52.7	50.9
Balance at the end of period	$500.1	$469.3	$500.1	$469.3

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2013	2012	2013	2012
Income statement data				
Revenues	$160.4	$150.3	$464.3	$450.1
Operating expenses	77.5	68.8	217.2	210.1
Other expense	20.2	21.0	62.6	62.1
Net income	$62.7	$60.5	$184.5	$177.9

(Millions)	September 30, 2013	December 31, 2012
Balance sheet data		
Current assets	$77.8	$63.1
Noncurrent assets	3,455.4	3,274.7
Total assets	$3,533.2	$3,337.8
Current liabilities	$353.6	$251.5
Long-term debt	1,550.0	1,550.0
Other noncurrent liabilities	119.9	95.8
Shareholders’ equity	1,509.7	1,440.5
Total liabilities and shareholders’ equity	$3,533.2	$3,337.8

NOTE 7 — INVENTORIES

PGL and NSG price natural gas storage injections at the calendar year average of the cost of natural gas supply purchased. Withdrawals from storage are priced on the 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, 2013, all LIFO layers were replenished, and the LIFO liquidation balance was zero.

NOTE 8 — GOODWILL AND OTHER INTANGIBLE ASSETS

The following table shows changes to our goodwill balances by segment during the nine months ended September 30, 2013:

(Millions)	Natural Gas Utility	Integrys Energy Services	Holding Company and Other	Total
Balance as of January 1, 2013				

Gross goodwill	$933.5	$6.6	$15.8	$955.9
Accumulated impairment losses	(297.6)	—	—	(297.6)
Net goodwill	635.9	6.6	15.8	658.3
Adjustment to ITF patents/intellectual property *	—	—	3.8	3.8
Balance as of September 30, 2013				
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

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

In the second quarter of 2013, annual impairment tests were completed at all of our reporting units that carried a goodwill balance. No impairments resulted from these tests.

Table of Contents

The identifiable intangible assets other than goodwill listed below are part of other current and long-term assets on the balance sheets. An insignificant amount was recorded as assets held for sale on the balance sheets.

(Millions)	September 30, 2013 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	December 31, 2012 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Customer-related [1]	$26.8	$ (15.3)	$11.5	$22.4	$ (14.7)	$7.7
Contractual service agreements [2]	15.6	(1.2)	14.4	—	—	—
Patents/intellectual property [3]	3.4	(0.4)	3.0	7.2	(0.3)	6.9
Compressed natural gas fueling contract assets [4]	5.6	(2.3)	3.3	5.6	(1.3)	4.3
Renewable energy credits [5]	5.1	—	5.1	3.1	—	3.1
Nonregulated easements [6]	3.7	(1.1)	2.6	3.8	(0.9)	2.9
Customer-owned equipment modifications [7]	4.0	(0.8)	3.2	4.0	(0.5)	3.5
Other	2.6	(0.8)	1.8	0.5	(0.2)	0.3
Total	$66.8	$ (21.9)	$44.9	$46.6	$ (17.9)	$28.7
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name [8]	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name [8]	1.5	—	1.5	1.5	—	1.5
Total intangible assets	$77.0	$ (21.9)	$55.1	$56.8	$ (17.9)	$38.9

(1) Represents customer relationship assets associated with PELLC's former nonregulated retail natural gas and electric operations, ITF's compressed natural gas fueling operations, and Compass Energy Services. See Note 4, "Acquisitions," for more information regarding Integrys Energy Services' acquisition of Compass Energy Services. The remaining weighted-average amortization period for customer-related intangible assets at September 30, 2013, was approximately 11 years.

(2) Represents contractual service agreements related to maintenance on the combustion turbine generators at the Fox Energy Center. The remaining amortization period for these intangible assets at September 30, 2013, was approximately seven years.

(3) 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. An immaterial adjustment was made to the intangible assets balance in the second quarter of 2013 as a result of a correction to the life of the intangible assets. The remaining amortization period at September 30, 2013, was approximately nine years.

(4) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at September 30, 2013, was approximately seven years.

(5) Used at Integrys Energy Services to comply with state Renewable Portfolio Standards and to support customer commitments.

(6) Relates to easements supporting a pipeline at Integrys Energy Services. The easements are amortized on a straight-line basis, with a remaining amortization period at September 30, 2013, of approximately 11 years.

(7) Relates to modifications made by Integrys Energy Services 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, 2013, of approximately 11 years.

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

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income for the three months ended September 30, 2013, and 2012, was $0.6 million and $0.3 million, respectively. Amortization expense for the nine months ended September 30, 2013, and 2012, was $1.5 million and $2.2 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the three months ended September 30, 2013, and 2012, was $1.3 million and $0.5 million, respectively. Amortization expense for the nine months ended September 30, 2013, and 2012, was $3.0 million and $2.0 million, respectively.

An insignificant amount of amortization expense was recorded in discontinued operations for the three and nine months ended September 30, 2013, and 2012.

The following table shows our estimated amortization expense for the next five years, including amounts recorded through September 30, 2013:

	For the Year Ending December 31				
(Millions)	2013	2014	2015	2016	2017
Amortization to be recorded in nonregulated cost of sales	$7.2	$2.2	$1.4	$0.9	$0.9
Amortization to be recorded in depreciation and amortization expense	4.2	4.3	4.2	4.0	3.9

15

Table of Contents

NOTE 9 — SHORT-TERM DEBT AND LINES OF CREDIT

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	September 30, 2013	December 31, 2012
Commercial paper	$188.0	$482.4
Average discount rate on commercial paper	0.17 %	0.40 %
Loan under term credit facility	$200.0	$—
Average interest rate on loan under term credit facility	0.78 %	—

Our average amount of commercial paper borrowings based on daily outstanding balances during the nine months ended September 30, 2013, and 2012, was $423.0 million and $299.2 million, respectively.

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our short-term debt and revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities:

(Millions)	Maturity	September 30, 2013	December 31, 2012
Revolving credit facility (Integrys Energy Group)	05/17/2014	$275.0	$275.0
Revolving credit facility (Integrys Energy Group)	05/17/2016	200.0	200.0
Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	635.0
Revolving credit facility (WPS)	05/17/2014	135.0	135.0
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0
Term credit facility (WPS)	12/31/2013	200.0	—
Total short-term credit capacity		$1,810.0	$1,610.0
Less:			
Letters of credit issued inside credit facilities		$37.4	$25.5
Loan outstanding under term credit facility		200.0	—
Commercial paper outstanding		188.0	482.4
Available capacity under existing agreements		$1,384.6	$1,102.1

The loan outstanding under the term credit facility relates to the purchase of Fox Energy Company LLC and must be repaid upon the earlier of WPS's issuance of replacement long-term debt or December 31, 2013. See Note 4, "Acquisitions," for more information regarding this purchase. The commercial paper outstanding at September 30, 2013, had maturity dates ranging from October 1, 2013, through October 7, 2013.

NOTE 10 — LONG-TERM DEBT

(Millions)	September 30, 2013	December 31, 2012
WPS (1)	$850.1	$872.1
PGL (2)	770.0	625.0
NSG (3)	88.5	74.5
Integrys Energy Group (4)	1,074.8	674.8

Total	2,783.4	2,246.4
Unamortized discount on debt	(0.7)	(1.2)
Total debt	2,782.7	2,245.2
Less current portion	276.5	313.5
Total long-term debt	$2,506.2	$1,931.7

(1) In February 2013, WPS's $22.0 million of 3.95% Senior Notes matured, and the outstanding principal balance was repaid.

In December 2013, WPS's 4.80% Senior Notes will mature. As a result, the $125.0 million balance of these notes was included in the current portion of long-term debt on our balance sheets.

(2) In April 2013, PGL bought back its $50.0 million of 5.00% Series KK First and Refunding Mortgage Bonds that were due in February 2033. In the same month, PGL issued $50.0 million of 4.00% Series ZZ First and Refunding Mortgage Bonds. These bonds are due in February 2033.

In May 2013, PGL's $75.0 million of 4.625% Series NN-2 First and Refunding Mortgage Bonds matured, and the outstanding principal balance was repaid.

In August 2013, PGL issued $220.0 million of 3.96% Series AAA First and Refunding Mortgage Bonds. These bonds are due in August 2043.

On November 1, 2013, PGL’s 7.00% Series SS First and Refunding Mortgage Bonds matured. As a result, the $45.0 million balance of these bonds was included in the current portion of long-term debt on our balance sheets.

(3) In May 2013, NSG’s $40.0 million of 4.625% Series N-2 First Mortgage Bonds matured, and the outstanding principal balance was repaid. In the same month, NSG issued $54.0 million of 3.96% Series Q First Mortgage Bonds. These bonds are due in May 2043.

On November 1, 2013, NSG’s 7.00% Series O First Mortgage Bonds matured. As a result, the $6.5 million balance of these bonds was included in the current portion of long-term debt on our balance sheets.

(4) In August 2013, we issued $400.0 million of Junior Subordinated Notes. Interest is payable quarterly at the stated rate of 6.00% for the first ten years, after which time it changes to a floating rate. These notes are due in August 2073.

In June 2014, our 7.27% Unsecured Senior Notes will mature. As a result, the $100.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at September 30, 2013.

NOTE 11 — 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			
	2013		2012		2013		2012	
Effective Tax Rate	31.4	%	28.5	%	36.3	%	32.2	%

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 tax rate of 35%. This difference was primarily due to a $3.7 million decrease in our provision for income taxes due to 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.

Our effective tax rate for the three months ended September 30, 2012, was lower than the federal statutory tax rate of 35%. This difference was partially due to a $5.9 million decrease in the provision for income taxes resulting from WPS's 2013 rate case settlement agreement. In the third quarter of 2012, WPS recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. See Note 21, "Regulatory Environment," for more information. Our effective tax rate was also impacted by the federal income tax benefit of tax credits related to wind production and other miscellaneous tax adjustments.

Our effective tax rate for the nine months ended September 30, 2012, was lower than the federal statutory tax rate of 35%. This difference was partially due to the settlement of certain state income tax examinations and the remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits in 2012. We decreased our provision for income taxes $6.2 million in 2012 primarily related to these items. In addition, our provision for income taxes decreased $5.9 million in 2012 related to the impact of WPS's 2013 rate case settlement agreement, as described above. Our effective tax rate was also impacted by the federal income tax benefit of tax credits related to wind production.

During the three months ended September 30, 2013, there was not a significant change in our liability for unrecognized tax benefits. During the nine months ended September 30, 2013, we decreased our liability for unrecognized tax benefits by $7.7 million. This decrease primarily related to remeasurements of uncertain tax positions driven by an effective settlement of certain state income tax examinations. We reduced the provision for income taxes related to these remeasurements, of which the majority was reported as discontinued operations.

Table of Contents

NOTE 12 — 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. Additionally, the majority of the energy supply contracts entered into by Integrys Energy Services are to meet its contractual obligations to deliver energy to customers. The following table shows our minimum future commitments related to these purchase obligations as of September 30, 2013, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Date Contracts Extend Through	Total Amounts Committed	2013	2014	2015	2016	2017	Later Years
Natural gas utility supply and transportation	2028	$839.8	$48.5	$171.0	$162.4	$148.5	$103.4	$206.0
Electric utility								
Purchased power	2029	795.5	37.6	66.5	32.6	28.8	27.7	602.3
Coal supply and transportation	2018	110.6	17.3	44.4	31.9	9.5	6.0	1.5
Nonregulated electricity and natural gas supply	2020	634.6	150.0	329.7	111.4	36.0	6.1	1.4
Total		$2,380.5	$253.4	$611.6	$338.3	$222.8	$143.2	$811.2

We and our subsidiaries also had commitments of $770.9 million in the form of purchase orders issued to various vendors at September 30, 2013, 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 (various options, including capital projects, are available), 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. As of September 30, 2013, no decision had been made on how to address this requirement. Therefore, retirement of the Weston and Pulliam 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.

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, 2013. 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 (Joint Owners) reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,

Table of Contents

- beneficial environmental projects, with WPS's portion totaling $1.3 million (various options, including capital projects, are available), 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, 2013, 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.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Edgewater plant did not comply with the CAA. A similar case had also been filed by the Sierra Club related to the Columbia plant but was dismissed without prejudice due to the impending settlement and Consent Decree. As part of the Consent Decree settlement, the Sierra Club filed a new lawsuit related to the Columbia plant, which gave notice of the filing of the Consent Decree. Both Sierra Club lawsuits against WP&L were dismissed when the Consent Decree was approved by the Court.

Weston Title V Air Permit:
In November 2010, the WDNR provided a draft revised permit for the Weston 4 plant. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR and met with the WDNR to resolve these issues. In September 2011, the WDNR issued an updated draft revised permit and a request for public comments. Due to the significance of the changes to the draft revised permit, the WDNR re-issued the draft revised permit for additional comments in February 2013. In July 2012, Clean Wisconsin filed a lawsuit against the WDNR alleging failure to issue or delay in issuing the Weston Title V permit. WPS and the WDNR both filed motions to dismiss Clean Wisconsin's lawsuit, which the Court granted in February 2013. Clean Wisconsin appealed this decision but voluntarily filed a dismissal of its appeal in July 2013, closing the lawsuit. The dismissal resulted from the WDNR sending the proposed permit to the EPA for action. Later in July 2013, the WDNR issued the 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 Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also filed Petitions for Review and requests for contested case proceedings regarding various aspects of the permit. On October 14, 2013, the WDNR granted all parties' requests for contested case proceedings, except one issue where they asked for clarifying information from WPS. The Petitions for Review, by all parties, have been stayed pending the resolution of the contested cases.

Columbia Title V Air Permit:
In February 2011, the Sierra Club filed a lawsuit against the EPA seeking to have the EPA take over the Title V permit process from the WDNR for the Columbia plant. The Sierra Club alleged the EPA must now act on the reconsideration of the Title V permit since the WDNR has exceeded its time frame in which to respond to an EPA order issued in 2009. In May 2011, the WDNR issued a revised draft Title V permit in response to the EPA's order. In June 2012, WP&L received notice from the EPA of the EPA's proposal for WP&L to apply for a federally-issued Title V permit since the WDNR had not addressed the EPA's objections to the Title V permit issued for the Columbia plant. Based on the entry of the Consent Decree, which covers the Columbia plant, the EPA has withdrawn its order, and this matter is now closed. This matter did not have a material impact on our financial statements.

WDNR Issued NOVs:
Since 2008, WPS received four NOVs from the WDNR alleging various violations of the different air permits for the entire Weston plant and Weston 1, Weston 2, and Weston 4 individually. WPS also received an NOV for a clerical

error involving pages missing from a quarterly report for Weston. Corrective actions were taken for the events in the five NOVs. In December 2011, the WDNR referred several of the claims in the NOVs to the state Justice Department for enforcement. In August 2013, WPS and the state Justice Department reached a settlement on these claims, which did not have a material impact on our financial statements.

Weston 4 Construction Permit

From 2004 to 2009, the Sierra Club filed various petitions objecting to the construction permit issued for the Weston 4 plant. In June 2010, the Wisconsin Court of Appeals affirmed the Weston 4 construction permit, but directed the WDNR to reopen the permit to set specific visible emissions limits. In July 2010, WPS, the WDNR, and the Sierra Club filed Petitions for Review with the Wisconsin Supreme Court. In March 2011, the Wisconsin Supreme Court denied all Petitions for Review. Other than the specific visible emissions limits issue, all other challenges to the construction permit are now resolved. WPS is working with the WDNR to resolve this issue as part of the current Title V air permit issued in July 2013 and subsequent proceedings discussed above. We do not expect this matter to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule requires a 40% reduction from historical baseline mercury emissions, beginning January 1, 2010, through the end of 2014. Beginning in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the historical baseline. 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. As of September 30, 2013, WPS estimates capital costs of approximately $9 million for its wholly owned plants to achieve the required reductions. The capital costs are expected to be recovered in future rates.

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 compliance date in the state mercury rules to be consistent with the MATS rule. We are currently evaluating options for achieving the emission limits specified in this rule, but we do not anticipate the cost of compliance to be significant. We expect to recover future compliance costs 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 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. In October 2012, the EPA and several other parties filed petitions for a rehearing of the D.C. Circuit's decision, which the D.C. Circuit denied in January 2013. In March 2013, the EPA requested that the United States Supreme Court (Supreme Court) review the D.C. Circuit's rejection of CSAPR. In June 2013, the Supreme Court agreed to review the case, but a decision is not expected until 2014.

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

Due to the uncertainty surrounding this rulemaking, we are currently unable to predict whether WPS will have to purchase additional emission allowances, idle or abandon certain units, or change how certain units are operated. WPS expects to recover any future compliance costs in future rates. The potential impact on Integrys Energy Services is not expected to be material.

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. They are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a "multi-site" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies.

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. As of September 30, 2013, we estimated and accrued for $612.1 million of 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, 2013, cash expenditures for environmental remediation not yet recovered in rates were $46.2 million. We recorded a regulatory asset of $658.3 million at September 30, 2013, which is net of insurance recoveries received of $64.9 million, related to the expected recovery through rates of both cash expenditures and estimated future expenditures.

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

NOTE 13 — GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at September 30, 2013	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$605.9	$390.3	$2.7	$212.9
Standby letters of credit (2)	40.8	40.7	0.1	—
Surety bonds (3)	20.6	15.6	5.0	—
Other guarantees (4)	23.5	—	—	23.5
Total guarantees	$690.8	$446.6	$7.8	$236.4

Table of Contents

(1) Consists of (a) $438.3 million, $5.0 million, and $2.0 million to support the business operations of Integrys Energy Services, IBS, and UPPCO, respectively, and (b) $110.5 million and $50.1 million related to natural gas supply at MERC and MGU, 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 $38.8 million issued to support Integrys Energy Services' operations and $2.0 million issued to support ITF, MERC, MGU, NSG, PGL, UPPCO, and WPS. These amounts are not reflected on our balance sheets.

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

(4) Consists of (a) $10.0 million related to the sale agreement for Integrys Energy Services' 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 tax law; (b) $5.0 million related to an environmental indemnification provided by Integrys Energy Services as part of the sale of the Stoneman generation facility, under which we expect that the likelihood of required performance is remote; (c) $2.4 million related to the performance of an operating and maintenance agreement by ITF; and (d) $6.1 million related to other indemnifications primarily for workers compensation coverage. The amounts discussed in items (b), (c), and (d) above are not reflected on our balance sheets.

We have provided total parental guarantees of $496.0 million on behalf of Integrys Energy Services. Our exposure under these guarantees related to existing transactions at September 30, 2013, was approximately $245.8 million.

NOTE 14 — EMPLOYEE BENEFIT PLANS

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

	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)	2013	2012	2013	2012	2013	2012	2013	2012
Service cost	$7.5	$11.5	$22.6	$34.5	$6.3	$5.2	$18.7	$15.6
Interest cost	17.8	19.5	53.4	58.5	6.2	7.1	18.6	21.4
Expected return on plan assets	(26.4)	(27.0)	(79.1)	(80.9)	(7.7)	(7.1)	(23.0)	(21.2)
Amortization of transition obligation	—	—	—	—	—	0.1	—	0.2
Amortization of prior service cost (credit)	1.0	1.3	3.0	3.8	(0.7)	(0.9)	(1.9)	(2.6)
Amortization of net actuarial loss	14.2	8.5	42.5	25.5	2.1	1.7	6.3	5.0
Net periodic benefit cost	$14.1	$13.8	$42.4	$41.4	$6.2	$6.1	$18.7	$18.4

Transition obligations, prior service costs (credits), and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are included in accumulated OCI for our nonregulated entities and are recorded as net regulatory assets for our utilities.

We make contributions to our plans in accordance with legal and tax requirements. These contributions do not necessarily occur evenly throughout the year. During the nine months ended September 30, 2013, we contributed $64.9 million to our pension plans and $0.1 million to our other postretirement benefit plans. We expect to contribute an additional $3.4 million to our pension plans and $32.8 million to our other postretirement benefit plans during the remainder of 2013, dependent upon various factors affecting us, including our liquidity position and tax law changes.

NOTE 15 — STOCK-BASED COMPENSATION

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

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	2013	2012	2013	2012
Stock options	$0.5	$0.5	$1.4	$1.5
Performance stock rights	1.2	0.5	4.4	4.8
Restricted share units	2.5	2.1	7.8	7.5
Nonemployee director deferred stock units	0.2	—	0.7	1.0
Total stock-based compensation expense	$4.4	$3.1	$14.3	$14.8
Deferred income tax benefit	$1.8	$1.2	$5.7	$5.9

No stock-based compensation cost was capitalized during the three and nine months ended September 30, 2013 and 2012.

Table of Contents

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. Our expected stock price volatility is estimated using the 10-year historical volatility of our stock price. The following table shows the weighted-average fair value per stock option granted during the nine months ended September 30, 2013, along with the assumptions incorporated into the valuation model:

	February 2013 Grant
Weighted-average fair value per option	$6.03
Expected term	5 years
Risk-free interest rate	0.18% – 2.11%
Expected dividend yield	5.33%
Expected volatility	24%

A summary of stock option activity for the nine months ended September 30, 2013, and information related to outstanding and exercisable stock options at September 30, 2013, 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, 2012	2,046,355	$ 49.25		
Granted	319,234	56.00		
Exercised	(793,455)	48.58		
Forfeited	(15,510)	56.00		
Outstanding at September 30, 2013	1,556,624	$ 50.91	6.5	$8.2
Exercisable at September 30, 2013	816,336	$ 49.92	4.8	$5.3

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, 2013. This is calculated as the difference between our closing stock price on September 30, 2013, 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, 2013, and 2012, was $9.0 million and $10.8 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises for the nine months ended September 30, 2013, and 2012, was $3.6 million and $4.4 million, respectively.

As of September 30, 2013, $1.5 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.0 years.

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 volatility is estimated using two to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at September 30:

	2013
Risk-free interest rate	0.26% – 1.27%
Expected dividend yield	5.18% – 5.34%

Expected volatility	19% – 36%

Table of Contents

A summary of the activity for the nine months ended September 30, 2013, 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, 2012	108,314	$ 65.38
Granted	22,636	48.50
Award modifications [1]	28,789	39.80
Distributed	(94,758)	72.36
Adjustment for final payout	21,867	72.36
Forfeited	(1,099)	48.50
Outstanding at September 30, 2013	85,749	$ 46.62

(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, 2013, and 2012, was $48.50 and $52.70, per performance stock right, respectively.

A summary of the activity for the nine months ended September 30, 2013, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2012	189,093
Granted	90,496
Award modifications *	(28,789)
Distributed	(61,753)
Adjustment for final payout	14,255
Forfeited	(4,398)
Outstanding at September 30, 2013	198,904

* 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, 2013, was $47.32 per performance stock right.

As of September 30, 2013, $3.0 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 1.5 years.

The total intrinsic value of performance stock rights distributed during the nine months ended September 30, 2013, and 2012, was $8.8 million and $4.7 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during the nine months ended September 30, 2013, and 2012, was $3.6 million and $1.9 million, respectively.

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, 2013, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2012	505,690	$ 48.38
Granted	196,894	55.93
Dividend equivalents	17,830	52.19
Vested and released	(207,411)	46.32
Forfeited	(5,997)	53.16
Outstanding at September 30, 2013	507,006	$ 52.24

Table of Contents

As of September 30, 2013, $12.6 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.3 years.

The total intrinsic value of restricted share unit awards vested and released during the nine months ended September 30, 2013, and 2012, was $11.6 million and $10.5 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, 2013, and 2012, was $4.7 million and $4.2 million respectively.

The weighted-average grant date fair value of restricted share units awarded during the nine months ended September 30, 2013, and 2012, was $55.93 and $53.24 per unit, respectively.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. The number of DSUs granted is calculated by dividing a set dollar amount by our closing common stock price on December 31 of the prior year. Prior to January 1, 2013, under the terms of the agreement, these awards vested immediately, and therefore were expensed on the grant date. Beginning in 2013, these awards generally vest over one year. Therefore, the expense for these awards is recognized pro-rata over the year in which the grant occurs.

NOTE 16 — COMMON EQUITY

We had the following changes to issued common stock during the nine months ended September 30, 2013:

Common stock issued at December 31, 2012	78,287,906
Shares issued	
Stock-based compensation	1,144,495
Stock Investment Plan	219,847
Rabbi trust shares	105,467
Common stock issued at September 30, 2013	79,757,715

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 02/05/2013	Issuing new shares *
01/01/2012 – 02/04/2013	Purchased shares on the open market

* These stock issuances increased equity $71.1 million in 2013.

The following table reconciles common shares issued and outstanding:

	September 30, 2013		December 31, 2012	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,757,715		78,287,906	
Less:				
Deferred compensation rabbi trust	467,967	$48.42	385,439	$46.03
Total common shares outstanding	79,289,748		77,902,467	

* 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.

Table of Contents

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. To the extent these items are accounted for as liability awards, the numerator is adjusted for any changes in income or loss that would have resulted had the awards been accounted for as equity awards 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)	2013	2012	2013	2012
Numerator:				
Net income from continuing operations	$39.4	$74.3	$217.7	$224.8
Discontinued operations, net of tax	(0.6)	(8.0)	4.7	(9.2)
Preferred stock dividends of subsidiary	(0.7)	(0.7)	(2.3)	(2.3)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Net income attributed to common shareholders — basic	$38.1	$65.7	$220.2	$213.4
Effect of dilutive securities				
Stock-based compensation	(0.1)	—	(0.1)	—
Net income attributed to common shareholders — diluted	$38.0	$65.7	$220.1	$213.4
Denominator:				
Average shares of common stock — basic	79.8	78.5	79.3	78.5
Effect of dilutive securities				
Stock-based compensation	0.4	0.6	0.4	0.6
Deferred compensation	—	0.2	0.2	0.2
Average shares of common stock — diluted	80.2	79.3	79.9	79.3
Earnings per common share				
Basic	$0.48	$0.84	$2.78	$2.72
Diluted	0.47	0.83	2.76	2.69

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)	2013	2012	2013	2012
Stock-based compensation	0.4	0.9	0.2	0.6
Deferred compensation	0.2	—	0.1	—

Dividend Restrictions

Our ability as a holding company to pay dividends is largely dependent upon the availability of funds from our subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our 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.

Table of Contents

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, 2013, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

As of September 30, 2013, total restricted net assets were $1,743.4 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $138.2 million at September 30, 2013.

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.

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, 2013, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
ITF (1)	$ —	$ —	$ 25.2
MERC	—	21.0	3.5
MGU	—	12.5	5.0
UPPCO	—	5.5	—
WPS	81.5	35.0	200.0
WPS Investments, LLC (2)	52.7	—	10.2
Total	$ 134.2	$ 74.0	$ 243.9

(1) ITF is a direct wholly owned subsidiary of PELLC. As a result, it makes distributions to PELLC, and receives 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, WPS, and UPPCO. At September 30, 2013, we had an 86.13% ownership interest, while WPS and UPPCO had an 11.44% and 2.43% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2013, all equity contributions to WPS Investments, LLC were made solely by us.

NOTE 17 — ACCUMULATED OTHER COMPREHENSIVE LOSS

The following tables show the changes, net of tax, to our accumulated other comprehensive loss during the three and nine months ended September 30, 2013:

Three Months Ended September 30, 2013 (Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Beginning balance at June 30, 2013	$ (2.1)	$ (34.5)	$ (36.6)

Amounts reclassified out of accumulated other comprehensive loss	0.3	0.6	0.9
Ending balance at September 30, 2013	$ (1.8)	$ (33.9)	$ (35.7)

Nine Months Ended September 30, 2013 (Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Beginning balance at December 31, 2012	$ (5.2)	$ (35.7)	$ (40.9)
Other comprehensive income before reclassifications	0.7	—	0.7
Amounts reclassified out of accumulated other comprehensive loss	2.7	1.8	4.5
Net current period other comprehensive income	3.4	1.8	5.2
Ending balance at September 30, 2013	$ (1.8)	$ (33.9)	$ (35.7)

Table of Contents

The following table shows the reclassifications out of accumulated other comprehensive loss during the three and nine months ended September 30, 2013:

(Millions)	Amount Reclassified Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Affected Line Item in the Statements of Income
Losses on cash flow hedges			
Utility commodity derivative contracts	$—	$0.2	Operating and maintenance expense[(1)]
Nonregulated commodity derivative contracts	0.2	3.4	Nonregulated revenues
Interest rate hedges	0.3	0.8	Interest expense
	0.5	4.4	Total before tax
	0.2	1.7	Tax expense
	0.3	2.7	Net of tax
Defined benefit plans			
Amortization of prior service costs	(0.1)	(0.2)	[(2)]
Amortization of net actuarial losses	1.1	3.2	[(2)]
	1.0	3.0	Total before tax
	0.4	1.2	Tax expense
	0.6	1.8	Net of tax
Total reclassifications	$0.9	$4.5	

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

(2) These items are included in the computation of net periodic benefit cost. See Note 14, "Employee Benefit Plans," for additional information.

NOTE 18 — VARIABLE INTEREST ENTITIES

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture is loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At September 30, 2013, and December 31, 2012, 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 not significant. The carrying amounts of AMP Trillium LLC assets and liabilities included on our balance sheets were also not significant.

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. The joint venture was established to own and operate compressed natural gas fueling stations. ITF and Paper Transport Inc. each initially owned 50% of the joint venture. We determined that the joint venture was a variable interest entity and that ITF was the primary beneficiary, which required us to consolidated the assets, liabilities, and statements of income of the joint venture. At December 31, 2012, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. The carrying amounts of Integrys PTI CNG Fuels LLC assets and liabilities included on our December 31, 2012, balance sheet were also not significant. In June 2013, ITF purchased Paper Transport Inc.'s 50% ownership interest of the joint venture, and it became a wholly-owned subsidiary.

We have a variable interest in an entity through a power purchase agreement at UPPCO that reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under this agreement. This contract for 17.5 megawatts of capacity expires in 2014. We evaluated this variable interest entity for possible consolidation. We considered which interest holder has the power to direct the activities that most significantly impact the economics of the variable interest entity; this interest holder is considered the primary beneficiary of the entity and is required to consolidate the entity. For a variety of reasons, including qualitative factors such as the length of the remaining term of the contract compared with the remaining life of the plant and the fact that we do not have the power to direct the operations and maintenance of the facility, we determined we are not the primary beneficiary of the variable interest entity. At September 30, 2013, and December 31, 2012, 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. We have not guaranteed any debt or provided any equity support, liquidity arrangements, performance guarantees, or other commitments associated with the contract. There is not a significant potential exposure to loss as a result of involvement with the variable interest entity.

We also had a variable interest in Fox Energy Company LLC through a power purchase agreement at WPS that contained a tolling arrangement related to the cost of fuel. In connection with the purchase of Fox Energy Company LLC in March 2013, WPS paid $50.0 million for the early termination of this 500-megawatt agreement. See Note 4, "Acquisitions," for more information regarding this purchase. We evaluated this variable interest entity for possible consolidation and determined that consolidation was not required since we were not the primary beneficiary of the variable interest entity. The assets and liabilities on our December 31, 2012, balance sheet 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.

Table of Contents

NOTE 19 — FAIR VALUE

Fair Value Measurements

A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities.

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methodologies.

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

Financial 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 where 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), price correlation (for cross commodity contracts), probability of default, and time value. These inputs are available through multiple sources, including brokers and over-the-counter and online exchanges. Transactions valued using these inputs are classified in Level 2.

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

•

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 group 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.

Table of Contents

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, 2013			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$0.9	$1.8	$—	$2.7
Financial transmission rights (FTRs)	—	—	3.4	3.4
Coal contracts	—	—	1.5	1.5
Nonregulated Segments				
Natural gas contracts	9.9	42.3	21.3	73.5
Electric contracts	70.1	49.0	12.8	131.9
Total Risk Management Assets	$80.9	$93.1	$39.0	$213.0
Investment in exchange-traded funds	$13.4	$—	$—	$13.4
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.8	$5.2	$—	$6.0
Petroleum product contracts	0.2	—	—	0.2
FTRs	—	—	0.4	0.4
Coal contracts	—	—	2.7	2.7
Nonregulated Segments				
Natural gas contracts	16.0	26.5	9.7	52.2
Electric contracts	75.6	69.9	10.1	155.6
Total Risk Management Liabilities	$92.6	$101.6	$22.9	$217.1
Contingent consideration related to the acquisition of Compass Energy Services (Compass) *	$—	$—	$7.7	$7.7

* See Note 4, "Acquisitions," for more information.

	December 31, 2012			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$0.3	$3.1	$—	$3.4
FTRs	—	—	2.1	2.1
Petroleum product contracts	0.2	—	—	0.2
Coal contracts	—	—	2.5	2.5
Nonregulated Segments				
Natural gas contracts	21.4	36.4	5.4	63.2
Electric contracts	48.4	61.3	9.6	119.3
Total Risk Management Assets	$70.3	$100.8	$19.6	$190.7
Investment in exchange-traded funds	$11.8	$—	$—	$11.8

Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$1.1	$14.1	$—	$15.2
FTRs	—	—	0.1	0.1
Coal contracts	—	—	9.0	9.0
Nonregulated Segments				
Natural gas contracts	17.7	36.9	1.5	56.1
Electric contracts	54.9	91.1	13.9	159.9
Total Risk Management Liabilities	$73.7	$142.1	$24.5	$240.3

Table of Contents

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. For more information on derivative instruments, see Note 3, "Risk Management Activities."

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

	Nonregulated Segments — Natural Gas Contracts					
	Three Months Ended September 30, 2013			Three Months Ended September 30, 2012		
(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	0.3	$—	N/A	0.3
Transfers into Level 3 from	—	2.5	N/A	—	0.4	N/A

	Nonregulated Segments — Natural Gas Contracts					
	Nine Months Ended September 30, 2013			Nine Months Ended September 30, 2012		
(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	0.3	$—	N/A	1.7
Transfers into Level 3 from	—	4.0	N/A	—	3.2	N/A

	Nonregulated Segments — Electric Contracts					
	Three Months Ended September 30, 2013			Three Months Ended September 30, 2012		
(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	(0.8)	$—	N/A	(1.9)
Transfers into Level 3 from	(0.2)	—	N/A	—	1.0	N/A

	Nonregulated Segments — Electric Contracts					
	Nine Months Ended September 30, 2013			Nine Months Ended September 30, 2012		
(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	4.6	$—	N/A	(5.8)
Transfers into Level 3 from	(0.2)	6.2	N/A	—	(7.8)	N/A

Derivatives are 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 significant unobservable inputs used in the valuation that resulted in categorization within Level 3 were as follows at September 30, 2013. The amounts and percentages listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	$ 3.4	$ 0.4	Market-based	Forward market prices ($/megawatt-month) (1)	$180.59
Coal contracts	1.5	2.7	Market-based	Forward market prices ($/ton) (2)	$12.21 — $14.63
Nonregulated Segments					
Natural gas contracts	21.3	9.7	Market-based		

				Forward market prices ($/dekatherm) (3)	($2.36) — $8.17
				Probability of default(4)	11.6% — 51.0%
Electric contracts	12.8	10.1	Market-based	Forward market prices ($/megawatt-hours) (3)	($7.15) — $9.25
				Probability of default(4)	26.0 %
				Option volatilities(5)	19.3% — 118.0%
				Monthly curve shaping(6)	(37.5)% — 25.6%
Contingent consideration related to the acquisition of Compass	N/A	7.7	Monte Carlo analysis	Growth rate(7)	(32)% — 157%

(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.

Table of Contents

(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.

(6) Represents adjustments made to forward market price curves to disaggregate average prices of multiple periods into discrete monthly prices.

(7) Represents the range of assumed growth rates of earnings before interest, taxes, and amortization input into the valuation model.

Significant changes in historical settlement prices, forward commodity prices, and option volatilities would result in a directionally similar significant change in fair value. Significant changes in probability of default would result in a significant directionally opposite change in fair value. Changes in the adjustments to prices related to monthly curve shaping would affect fair value differently depending on their direction. A significant decrease in the growth rate used to value the contingent consideration would result in a directionally similar significant change in fair value. A significant increase in the growth rate would not have a significant impact on the fair value as the contingent consideration is limited to $8.0 million.

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, 2013	Nonregulated Segments			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

* Represents the contingent consideration related to the acquisition of Compass. See Note 4 "Acquisitions," for more information.

Nine Months Ended September 30, 2013	Nonregulated Segments			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)
	1.3	7.6	—	1.7	—	10.6

Net realized and unrealized gains included in earnings						
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

* Represents the contingent consideration related to the acquisition of Compass. See Note 4 "Acquisitions," for more information.

Table of Contents

Three Months Ended September 30, 2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$ 6.3	$ (14.7)	$ 4.8	$ (9.8)	$ (13.4)
Net realized and unrealized gains (losses) included in earnings	2.7	2.6 *	(1.0)	—	4.3
Net unrealized (losses) gains recorded as regulatory assets or liabilities	—	—	(0.2)	2.1	1.9
Settlements	(6.7)	(0.1)	(0.4)	(1.6)	(8.8)
Net transfers into Level 3	0.4	1.0	—	—	1.4
Net transfers out of Level 3	(0.3)	1.9	—	—	1.6
Balance at the end of the period	$ 2.4	$ (9.3)	$ 3.2	$ (9.3)	$ (13.0)
Net unrealized gains included in earnings related to instruments still held at the end of the period	$ 2.7	$ 2.6 *	$ —	$ —	$ 5.3

* Includes a $0.2 million net unrealized loss reported as discontinued operations. See Note 5, "Discontinued Operations," for more information.

Nine Months Ended September 30, 2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$ 8.3	$ (11.5)	$ 2.2	$ (6.9)	$ (7.9)
Net realized and unrealized gains (losses) included in earnings	1.9	(5.3) *	1.5	—	(1.9)
Net unrealized gains recorded as regulatory assets or liabilities	—	—	0.1	1.5	1.6
Purchases	—	2.1	4.9	—	7.0
Sales	—	—	(0.1)	—	(0.1)
Settlements	(9.3)	7.4	(5.4)	(3.9)	(11.2)
Net transfers into Level 3	3.2	(7.8)	—	—	(4.6)
Net transfers out of Level 3	(1.7)	5.8	—	—	4.1
Balance at the end of the period	$ 2.4	$ (9.3)	$ 3.2	$ (9.3)	$ (13.0)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 1.9	$ (5.3) *	$ —	$ —	$ (3.4)

* Includes a $0.6 million net unrealized loss reported as discontinued operations. See Note 5, "Discontinued Operations," for more information.

Realized and unrealized gains and losses included in earnings related to Integrys Energy Services’ risk management assets and liabilities are 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, 2013		December 31, 2012	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$2,782.7	$2,768.5	$2,245.2	$2,425.8
Preferred stock of subsidiary	51.1	61.6	51.1	52.7

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, notes payable, and outstanding commercial paper, the carrying amount for each of these items approximates fair value.

Table of Contents

NOTE 20 — ADVERTISING COSTS

Costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services 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 \$5.2 million and \$5.5 million as of September 30, 2013, and December 31, 2012, respectively. 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, 2013, and 2012.

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 and \$1.0 million for the three months ended September 30, 2013, and 2012, respectively. The amortization of direct-response advertising costs was \$4.1 million and \$2.3 million for the nine months ended September 30, 2013, and 2012, respectively.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. Other advertising expense was \$2.2 million and \$2.1 million, for the three months ended September 30, 2013, and 2012, respectively. Other advertising expense was \$6.6 million and \$5.2 million, for the nine months ended September 30, 2013, and 2012, respectively.

NOTE 21 — REGULATORY ENVIRONMENT

Wisconsin

2014 Rate Case

In March 2013, WPS filed an application with the PSCW to increase retail electric and natural gas rates \$71.1 million and \$19.0 million, respectively, with rates proposed to be effective January 1, 2014. The filing includes a request for a 10.75% return on common equity and a common equity ratio of 51.11% in WPS's regulatory capital structure. The proposed retail electric rate increase is primarily driven by the purchase and operation of the Fox Energy Center, the completion of a one-time fuel refund to customers in 2013, increased electric transmission costs, additional construction related to the installation of environmental controls and the improvement of electric reliability, the recovery of pension and other employee benefit costs deferred in 2013 rates, and general inflation. Partially offsetting these increases are lower purchased power capacity costs and a refund to customers resulting from WPS's decoupling mechanism. The proposed retail natural gas rate increase is generally the result of the recovery of amounts related to decoupling, increased costs of inspecting natural gas lines for safety, the recovery of pension and other employee benefit costs deferred in 2013 rates, and general inflation.

In August 2013, the PSCW Staff submitted testimony and recommended rate increases of \$9.3 million and \$7.8 million for retail electric and natural gas, respectively, reflecting a 10.20% return on common equity. Their recommendation also included a common equity ratio of 50.14% in WPS's regulatory capital structure. The PSCW held both technical and public hearings in September 2013. In October 2013, WPS issued an initial brief revising its requested retail electric and natural gas rate increases to approximately \$60 million and approximately \$14 million, respectively, including a reduced return on common equity of 10.60%. Included in these revised amounts, is WPS's request for recovery of \$1.7 million for the Wisconsin retail allocation of environmental remediation capital and operating costs related to WPS's Consent Decree with the EPA. See Note 12, "Commitments and Contingencies," for more information. Finally, WPS requested the removal of the annual caps associated with the decoupling mechanism that is currently in place. WPS's revised request is a result of WPS's current position on contested issues. New rates are expected to be effective January 1, 2014.

2013 Rates

In December 2012, the PSCW issued an order approving a settlement agreement for WPS, effective January 1, 2013. The settlement agreement included a $28.5 million imputed retail electric rate increase, partially offset by the actual 2012 fuel refund of $20.5 million. The difference between the 2012 fuel refund and the rate increase is being deferred for recovery in a future rate proceeding. As a result, there was no change to customers' 2013 retail electric rates. The settlement agreement also included a $3.4 million retail natural gas rate decrease, which included a deferral of $2.1 million of pension and other employee benefit costs that will be recovered in a future rate proceeding. The 2013 electric and natural gas rates were reduced based on updated December 31, 2012, pension and other employee benefit cost estimates, which were filed with the PSCW in March 2013. The settlement agreement reflected a 10.30% return on common equity and a common equity ratio of 51.61% in WPS's regulatory capital structure. 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 settlement agreement also authorized the recovery of direct Cross State Air Pollution Rule (CSAPR) costs incurred through the end of 2012. Lastly, the settlement agreement authorized WPS to switch from production tax credits to Section 1603 Grants for the Crane Creek Wind Project.

A new decoupling mechanism for natural gas and electric residential and small commercial and industrial customers was approved as part of the settlement agreement on a pilot basis for 2013. The mechanism is based on total rate case-approved margins, rather than being calculated on a per-customer basis. The mechanism does not cover all customer classes, and it continues to include an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are subject to these caps and are included in rates upon approval in a rate proceeding.

2012 Rates

In December 2011, the PSCW issued a final written order for WPS, effective January 1, 2012. It authorized an electric rate increase of $8.1 million and required a natural gas rate decrease of $7.2 million. The electric rate increase was driven by projected increases in fuel and purchased power costs. However, to the extent that actual fuel and purchased power costs exceeded a 2% price variance from costs included in rates, they were deferred for recovery or refund in a future rate proceeding. The rate order allowed for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection and reflected reduced contributions to the Focus on Energy Program. The rate order also allowed for the deferral of direct CSAPR compliance costs, including carrying costs.

Michigan

2014 MGU Rate Case

In October 2013, MGU entered into a settlement agreement with the MPSC and all other involved parties resolving all issues in the MGU 2014 rate case. The settlement agreement provides for a retail natural gas rate increase of $4.5 million, effective January 1, 2014. 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 requires MGU to terminate its existing decoupling mechanism, effective December 31, 2013, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2015. The decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. The rate order also terminates 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 Rate Case

In June 2013, UPPCO filed an application with the MPSC to increase retail electric rates $7.9 million. Interim rates could be effective on January 1, 2014. UPPCO's request reflects a 10.75% return on common equity and a common equity ratio of 54.98% in its regulatory capital structure. The request was primarily driven by capital investments associated with FERC mandated replacements and upgrades of hydroelectric facilities, and increased costs associated with uncollectibles expense, line clearance, system losses, and general inflation. UPPCO is also requesting authority from the MPSC to implement a revenue adjustment mechanism that operates similar to a decoupling mechanism.

2012 UPPCO Rates

In December 2011, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $4.2 million, effective January 1, 2012. The new rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in its regulatory capital structure. The order stated that if UPPCO filed a rate case in 2013, the earliest effective date for new final rates or self-implemented rates would be January 1, 2014.

Additionally, the order required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2013. The new decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. It includes an annual 1.5% cap based on distribution revenues approved in the rate case. UPPCO had no decoupling mechanism in place during 2012.

In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. This decision was not appealed. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. However, in August 2012, the MPSC issued an order stating it had the authority to approve UPPCO's decoupling mechanism, as UPPCO's decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement. Therefore, in the third quarter of 2012, UPPCO reversed the $1.5 million previously expensed in the first quarter of 2012.

Table of Contents

Illinois

Qualifying Infrastructure Plant (QIP) 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 cost recovery mechanism for Illinois natural gas infrastructure upgrades that will be collected through a surcharge on customer bills. Later in July 2013, the ICC adopted emergency rules to implement the law. The ICC also opened a docket to develop permanent rules, which will replace the emergency rules. This Act eliminates a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation once PGL obtains an infrastructure tariff. In September 2013, PGL filed with the ICC requesting the proposed rider. The ICC must act no later than January 17, 2014. The ICC may modify the rider only to ensure compliance with the law. The rider would take effect on January 1 of the year in which the ICC issues its order.

2013 Rates

In June 2013, the ICC issued a final order authorizing a retail natural gas rate increase of $57.2 million for PGL and $6.6 million for NSG, effective June 27, 2013. The rates for PGL reflect a 9.28% return on common equity and a common equity ratio of 50.43% in its regulatory capital structure. The rates for NSG reflect a 9.28% return on common equity and a common equity ratio of 50.32% in its regulatory capital structure. The rate order also allows PGL and NSG to continue the use of their decoupling mechanisms, as affirmed by the Illinois Appellate Court (Court).

In August 2013, the ICC granted certain rehearing requests on tax-related issues filed by PGL, NSG, and other intervenors. PGL and NSG had 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 have 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. If the deferred tax asset created by the 2012 tax NOL is excluded from rate base or the corrections requested by PGL and NSG are not made, there is a potential that the federal income tax "normalization" rules could be violated. These rules specify that the benefit of claiming accelerated depreciation for federal income tax purposes cannot be given to customers before the tax cash flow is received by the company. Once received, the benefit must be given to customers over the useful life of the underlying property. A violation could cause PGL and NSG to lose the ability to claim accelerated depreciation deductions for income tax purposes. We believe this outcome is unlikely.

2012 Rates

In January 2012, the ICC issued a final order authorizing a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG, effective January 21, 2012. The rates for PGL reflected a 9.45% return on common equity and a common equity ratio of 49.00% in PGL's regulatory capital structure. The rates for NSG reflected a 9.45% return on common equity and a common equity ratio of 50.00% in NSG's regulatory capital structure. The rate order also approved a permanent decoupling mechanism.

The Illinois Attorney General and Citizens Utility Board appealed to the Court the ICC's authority to approve PGL's and NSG's decoupling mechanism 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. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 were uncertain, and PGL and NSG had 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 is in place for 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. The Illinois Supreme Court granted the request in September 2013. The Illinois Supreme Court has no deadline by which it must act. Decoupling amounts recorded in 2012 and 2013 are expected to be recovered or refunded, absent an adverse Illinois Supreme Court decision. Between April 1, 2013 and December 31, 2013, PGL and NSG expect to recover $14.8 million and $1.7 million, respectively, related to their 2012 decoupling mechanisms. As of September 30, 2013, PGL and NSG have recovered $6.4 million and $0.8 million, respectively, related to the 2012 decoupling mechanisms.

Minnesota

2014 Rate Case

In September 2013, MERC filed an application with the MPUC to increase retail natural gas distribution rates by $14.2 million. Interim rates could be effective on January 1, 2014. MERC's request reflects a 10.75% return on common equity and a common equity ratio of 50.31% in its regulatory capital structure. The request was primarily driven by general inflation, property taxes, improvements to customer service programs, efforts to expand the customer base which would have a positive rate effect in the future, and operating and maintenance projects to ensure reliability and safety for customers.

Table of Contents

2011 Rates

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

Federal

Through a series of orders issued by the FERC, Regional Through and Out Rates for transmission service between the MISO and the PJM Interconnection were eliminated effective December 1, 2004. To compensate transmission owners for the revenue they would no longer receive due to this rate elimination, the FERC ordered a transitional pricing mechanism called the Seams Elimination Charge Adjustment (SECA) be put into place. Load-serving entities paid these SECA charges during a 16-month transition period from December 1, 2004, through March 31, 2006.

Integrys Energy Services initially expensed the majority of the total $19.2 million of billings paid during the transitional period. The remaining amount was considered probable of recovery due to inconsistencies between the FERC's SECA order and the transmission owners' FERC-ordered compliance filings. Integrys Energy Services protested the FERC’s SECA order, and through various rulings, ultimately received adverse decisions on most substantive issues. Integrys Energy Services appealed the adverse FERC decisions to the U.S. Court of Appeals for the D.C. Circuit.

In January 2013, Integrys Energy Services reached a settlement on all remaining issues with American Electric Power Service Corporation (AEP), the transmission owner affected the most from SECA payments collected from Integrys Energy Services. The parties filed a Joint Stipulation and Agreement ("Settlement Agreement") with the FERC in January 2013. In July 2013, the FERC issued an order approving the uncontested Settlement Agreement. In September 2013, AEP made a lump sum payment of $9.5 million to Integrys Energy Services in complete settlement of the matters at issue (which included a $3.8 million receivable previously recorded). As a result, Integrys Energy Services recorded $5.7 million in other income, representing the portion of the $9.5 million settlement not previously recognized. In September 2013, Integrys Energy Services withdrew its petitions for review filed with the U.S. Court of Appeals for the D.C. Circuit, as discussed above.

NOTE 22 — SEGMENTS OF BUSINESS

At September 30, 2013, 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.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.
-

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.

Table of Contents

The tables below present information related to our reportable segments:

(Millions)	Regulated Operations				Nonutility and Nonregulated Operations			
	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	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

(Millions)	Regulated Operations				Nonutility and Nonregulated Operations			
	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended September 30, 2012								
External revenues	$215.5	$366.8	$ —	$ 582.3	$335.5	$9.9	$ —	$ 927.7
Intersegment revenues	4.5	—	—	4.5	0.1	0.3	(4.9)	—
Depreciation and amortization expense	33.2	22.3	—	55.5	2.7	4.8	(0.1)	62.9
Earnings from equity method investments	—	—	21.7	21.7	0.5	—	—	22.2
Miscellaneous income	0.1	0.9	—	1.0	0.3	5.7	(3.9)	3.1
Interest expense	11.7	8.9	—	20.6	0.5	12.7	(3.9)	29.9
Provision (benefit) for income taxes	(11.5)	19.5	8.3	16.3	16.1	(2.8)	—	29.6
	(13.9)	47.8	13.4	47.3	32.2	(5.2)	—	74.3

Net income (loss) from continuing operations								
Discontinued operations	—	—	—	—	(8.0)	—	—	(8.0)
Preferred stock dividends of subsidiary	(0.1)	(0.6)	—	(0.7)	—	—	—	(0.7)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	(14.0)	47.2	13.4	46.6	24.2	(5.1)	—	65.7

Table of Contents

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	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						