INTEGRYS ENERGY GROUP, INC.
Form 10-Q
August 09, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

OR

o 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	Internal Revenue Service Employer Identification No.
1-11337	**INTEGRYS ENERGY GROUP, INC.** (A Wisconsin Corporation) 130 East Randolph Street Chicago, Illinois 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 o

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 o

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 o
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o 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,
78,287,906 shares outstanding at
August 2, 2012

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INTEGRYS ENERGY GROUP, INC.

QUARTERLY REPORT ON FORM 10-Q

For the Quarter Ended June 30, 2012

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Commonly Used Acronyms in this Quarterly Report on Form 10-Q

AMRP	Accelerated Natural Gas Main Replacement Program
ASU	Accounting Standards Update
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
ICR	Infrastructure Cost Recovery
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	Midwest Independent Transmission System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utility 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

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Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions, but rather are subject to numerous management assumptions, risks, and uncertainties. Therefore, actual results may differ materially from those expressed or implied by these statements. 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, 2011, 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 coal-fired 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, including manufactured gas plant site cleanup, third-party intervention in permitting and licensing projects, compliance with Clean Air Act requirements at generation plants, and prudence and reconciliation of costs recovered in revenues through automatic gas cost recovery mechanisms;

- 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 all of 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.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited) (Millions, except per share data)	Three Months Ended June 30 2012	 2011	Six Months Ended June 30 2012	 2011
Utility revenues	**$ 563.6**	$ 670.8	**$ 1,534.6**	$ 1,839.5
Nonregulated revenues	**278.3**	340.0	**558.6**	798.4
Total revenues	**841.9**	1,010.8	**2,093.2**	2,637.9
Utility cost of fuel, natural gas, and purchased power	**225.9**	305.2	**698.2**	965.9
Nonregulated cost of sales	**193.5**	291.0	**468.8**	695.0
Operating and maintenance expense	**252.2**	261.1	**513.2**	525.7
Depreciation and amortization expense	**63.2**	62.2	**125.9**	124.5
Taxes other than income taxes	**23.0**	23.8	**51.4**	50.6
Operating income	**84.1**	67.5	**235.7**	276.2
Earnings from equity method investments	**22.2**	20.3	**43.3**	39.7
Miscellaneous income	**1.7**	1.3	**4.1**	3.1
Interest expense	**(29.9)**	(32.2)	**(60.4)**	(67.0)
Other expense	**(6.0)**	(10.6)	**(13.0)**	(24.2)
Income before taxes	**78.1**	56.9	**222.7**	252.0
Provision for income taxes	**28.4**	26.1	**75.2**	97.8
Net income from continuing operations	**49.7**	30.8	**147.5**	154.2
Discontinued operations, net of tax	**(0.1)**	(0.9)	**1.8**	(0.8)
Net income	**49.6**	29.9	**149.3**	153.4
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)	**(1.6)**	(1.6)
Net income attributed to common shareholders	**$ 48.8**	$ 29.1	**$ 147.7**	$ 151.8
Average shares of common stock				
Basic	**78.5**	78.7	**78.5**	78.5
Diluted	**79.3**	79.1	**79.3**	78.8
Earnings (loss) per common share (basic)				
Net income from continuing operations	**$ 0.62**	$ 0.38	**$ 1.86**	$ 1.94
Discontinued operations, net of tax		(0.01)	**0.02**	(0.01)
Earnings per common share (basic)	**$ 0.62**	$ 0.37	**$ 1.88**	$ 1.93
Earnings (loss) per common share (diluted)				
Net income from continuing operations	**$ 0.62**	$ 0.38	**$ 1.84**	$ 1.94
Discontinued operations, net of tax		(0.01)	**0.02**	(0.01)
Earnings per common share (diluted)	**$ 0.62**	$ 0.37	**$ 1.86**	$ 1.93

Dividends per common share declared	**$ 0.68**	$ 0.68	**$ 1.36**	$ 1.36

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited) (Millions)	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Net income	**$ 49.6**	$ 29.9	**$ 149.3**	$ 153.4
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net gains (losses) arising during period, net of tax of $ - million, $3.6 million, $(0.2) million, and $1.2 million, respectively	**0.1**	6.0	**(0.2)**	1.9
Reclassification of net losses (gains) to net income, net of tax of $0.6 million, $(2.3) million, $1.6, million and $2.8 million, respectively	**1.0**	(4.3)	**2.5**	4.1
Cash flow hedges, net	**1.1**	1.7	**2.3**	6.0
Defined benefit pension plans				
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.2 million, $ - million, $0.5 million, and $0.2 million, respectively	**0.4**	0.3	**0.7**	0.5
Other comprehensive income, net of tax	**1.5**	2.0	**3.0**	6.5
Comprehensive income	**51.1**	31.9	**152.3**	159.9
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)	**(1.6)**	(1.6)
Comprehensive income attributed to common shareholders	**$ 50.3**	$ 31.1	**$ 150.7**	$ 158.3

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (Millions)	June 30 2012	December 31 2011
Assets		
Cash and cash equivalents	$ 25.7	$ 28.1
Collateral on deposit	58.0	50.9
Accounts receivable and accrued unbilled revenues, net of reserves of $42.5 and $47.1, respectively	493.1	737.7
Inventories	141.8	252.3
Assets from risk management activities	195.4	227.2
Regulatory assets	112.8	125.1
Deferred income taxes	108.6	94.2
Prepaid taxes	152.9	209.6
Other current assets	90.6	78.2
Current assets	1,378.9	1,803.3
Property, plant, and equipment, net of accumulated depreciation of $3,092.9 and $3,018.7, respectively	5,358.6	5,199.1
Regulatory assets	1,635.8	1,658.5
Assets from risk management activities	53.1	64.4
Equity method investments	496.9	476.3
Goodwill	658.3	658.4
Other long-term assets	127.4	123.2
Total assets	$ 9,709.0	$ 9,983.2
Liabilities and Equity		
Short-term debt	$ 279.0	$ 303.3
Current portion of long-term debt	387.0	250.0
Accounts payable	371.9	426.6
Liabilities from risk management activities	264.2	311.6
Accrued taxes	40.4	70.5
Regulatory liabilities	95.1	67.5
Other current liabilities	189.9	217.2
Current liabilities	1,627.5	1,646.7
Long-term debt	1,735.0	1,872.0
Deferred income taxes	1,153.3	1,070.7
Deferred investment tax credits	45.4	44.0
Regulatory liabilities	338.1	332.5
Environmental remediation liabilities	604.5	615.1
Pension and other postretirement benefit obligations	521.5	749.3
Liabilities from risk management activities	86.1	102.0
Asset retirement obligations	407.9	397.2
Other long-term liabilities	143.9	141.1
Long-term liabilities	5,035.7	5,323.9
Commitments and contingencies		
Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,912,113 shares outstanding	78.3	78.3
Additional paid-in capital	2,568.4	2,579.1
Retained earnings	404.6	363.6

Accumulated other comprehensive loss		**(39.5)**		(42.5)
Shares in deferred compensation trust		**(17.2)**		(17.1)
Total common shareholders equity		**2,994.6**		2,961.4
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		**51.1**		51.1
Noncontrolling interest in subsidiaries		**0.1**		0.1
Total liabilities and equity	**$**	**9,709.0**	$	9,983.2

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited) (Millions)	Six Months Ended June 30 2012	2011
Operating Activities		
Net income	$ **149.3**	$ 153.4
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	**(1.8)**	0.8
Depreciation and amortization expense	**125.9**	124.5
Recoveries and refunds of regulatory assets and liabilities	**14.9**	23.9
Net unrealized gains on energy contracts	**(1.3)**	(9.7)
Nonregulated lower of cost or market inventory adjustments	**4.2**	0.3
Bad debt expense	**15.1**	20.3
Pension and other postretirement expense	**35.4**	36.1
Pension and other postretirement contributions	**(247.3)**	(108.9)
Deferred income taxes and investment tax credits	**65.9**	126.9
Gain on sale of assets	**(2.1)**	(0.5)
Equity income, net of dividends	**(9.1)**	(7.8)
Other	**4.5**	12.8
Changes in working capital		
Collateral on deposit	**(7.5)**	(3.0)
Accounts receivable and accrued unbilled revenues	**223.8**	236.7
Inventories	**116.3**	86.0
Other current assets	**45.5**	(12.1)
Accounts payable	**(62.6)**	(54.1)
Temporary LIFO liquidation credit	**2.5**	54.8
Other current liabilities	**(37.9)**	(92.2)
Net cash provided by operating activities	**433.7**	588.2
Investing Activities		
Capital expenditures	**(249.2)**	(114.5)
Proceeds from the sale or disposal of assets	**5.9**	3.3
Capital contributions to equity method investments	**(15.5)**	(11.0)
Other	**(3.7)**	(0.3)
Net cash used for investing activities	**(262.5)**	(122.5)
Financing Activities		
Short-term debt, net	**(24.3)**	57.6
Redemption of notes payable		(10.0)
Issuance of long-term debt	**28.0**	
Repayment of long-term debt	**(28.2)**	(355.2)
Payment of dividends		
Preferred stock of subsidiary	**(1.6)**	(1.6)
Common stock	**(106.0)**	(100.4)
Issuance of common stock		4.9
Payments made on derivative contracts related to divestitures classified as financing activities	**(19.8)**	(20.2)
Other	**(21.7)**	(8.4)
Net cash used for financing activities	**(173.6)**	(433.3)
Net change in cash and cash equivalents	**(2.4)**	32.4
Cash and cash equivalents at beginning of period	**28.1**	179.0
Cash and cash equivalents at end of period	$ **25.7**	$ 211.4

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

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INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES

CONDENSED NOTES TO FINANCIAL STATEMENTS

June 30, 2012

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 t 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, 2011.

In management s opinion, these unaudited financial statements include all adjustments considered 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. Financial results for an interim period may not give a true indication of results for the year.

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 supplemental disclosure to our statements of cash flows:

	Six Months Ended June 30	
(Millions)	**2012**	**2011**
Cash paid for interest	**$ 55.1**	$ 71.1
Cash (received) paid for income taxes	**(35.7)**	3.2

Significant noncash transactions were:

	Six Months Ended June 30			
(Millions)	**2012**		**2011**	
Construction costs funded through accounts payable	**$**	**79.7**	$	23.7
Equity issued for stock-based compensation plans				15.8
Equity issued for reinvested dividends				5.4

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NOTE 3 RISK MANAGEMENT ACTIVITIES

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

(Millions)	Balance Sheet Presentation *	June 30, 2012 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ **10.6**	$ **26.1**
Natural gas contracts	Long-term	**0.9**	**4.9**
Financial transmission rights (FTRs)	Current	**5.0**	**0.2**
Petroleum product contracts	Current		**0.1**
Coal contract	Current		**5.7**
Coal contract	Long-term		**4.1**
Cash flow hedges			
Natural gas contracts	Current		**0.9**
Natural gas contracts	Long-term		
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**86.6**	**81.7**
Natural gas contracts	Long-term	**20.3**	**16.2**
Electric contracts	Current	**93.0**	**149.3**
Electric contracts	Long-term	**31.9**	**60.9**
Foreign exchange contracts	Current	**0.2**	**0.2**
	Current	**195.4**	**264.2**
	Long-term	**53.1**	**86.1**
Total		$ **248.5**	$ **350.3**

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

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(Millions)	Balance Sheet Presentation *	December 31, 2011 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 9.1	$ 35.4
Natural gas contracts	Long-term	0.1	8.2
FTRs	Current	2.3	0.1
Petroleum product contracts	Current	0.1	
Coal contract	Current		2.5
Coal contract	Long-term		4.4
Cash flow hedges			
Natural gas contracts	Current		0.9
Natural gas contracts	Long-term		0.2
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	121.6	120.5
Natural gas contracts	Long-term	41.9	40.5
Electric contracts	Current	93.9	152.0
Electric contracts	Long-term	22.4	48.7
Foreign exchange contracts	Current	0.2	0.2
	Current	227.2	311.6
	Long-term	64.4	102.0
Total		$ 291.6	$ 413.6

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

The following table shows our cash collateral positions:

(Millions)	June 30, 2012	December 31, 2011
Cash collateral provided to others	**$ 58.0**	$ 50.9
Cash collateral received from others *	**1.1**	2.3

* Reflected in other current liabilities on the balance sheets.

Certain of our derivative and nondderivative 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)	June 30, 2012	December 31, 2011
Integrys Energy Services	**$ 160.9**	$ 193.8
Utility segments	**31.1**	39.1

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)		June 30, 2012	December 31, 2011
Collateral that would have been required:			
Integrys Energy Services		**$ 205.0**	$ 272.3
Utility segments		**24.5**	28.7
Collateral already satisfied:			
Integrys Energy Services	Letters of credit	**1.9**	11.0
Collateral remaining:			
Integrys Energy Services		**203.1**	261.3
Utility segments		**24.5**	28.7

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Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, a coal purchase contract, 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 non-hedge derivative contracts:

	June 30, 2012		December 31, 2011	
	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**754.6**	**N/A**	1,122.7	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**8,977.2**	N/A	5,077.5
Petroleum products (barrels)	**42,911.0**	**N/A**	46,872.0	N/A
Coal contract (millions of tons)	**3.7**	**N/A**	4.1	N/A

The tables below show the unrealized gains (losses) recorded related to non-hedge derivatives at the utilities:

(Millions)	Financial Statement Presentation		Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Natural gas contracts	Balance Sheet	Regulatory assets (current)	**$ 19.1**	$ 2.2	**$ 12.7**	$ 13.4
Natural gas contracts	Balance Sheet	Regulatory assets (long-term)	**4.7**	(1.4)	**3.9**	0.2
Natural gas contracts	Balance Sheet	Regulatory liabilities (current)	**4.2**		**0.5**	(0.1)
Natural gas contracts	Balance Sheet	Regulatory liabilities (long-term)	**0.4**	(0.1)	**0.5**	
Natural gas contracts	Income Statement	Utility cost of fuel, natural gas, and purchased power			**0.1**	0.1
FTRs	Balance Sheet	Regulatory assets (current)	**(0.8)**	(1.6)	**(0.4)**	(1.5)
FTRs	Balance Sheet	Regulatory liabilities (current)	**1.0**	1.1	**0.7**	(0.1)
Petroleum product contracts	Balance Sheet	Regulatory assets (current)	**(0.2)**	(0.1)	**(0.1)**	(0.1)
Petroleum product contracts	Balance Sheet	Regulatory liabilities (current)	**(0.1)**	(0.2)		0.2
Petroleum product contracts	Income Statement	Operating and maintenance expense	**(0.1)**	(0.3)		0.2
Coal contract	Balance Sheet	Regulatory assets (current)	**(0.1)**	0.3	**(3.2)**	(0.2)

Coal contract	Balance Sheet (long-term)	Regulatory assets	**3.7**	0.2	**0.2**	(3.0)
Coal contract	Balance Sheet (long-term)	Regulatory liabilities				(3.7)

Nonregulated Segments

Non-Hedge 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 non-hedge derivative contracts:

	June 30, 2012		**December 31, 2011**	
(Millions)	**Purchases**	**Sales**	**Purchases**	**Sales**
Commodity contracts				
Natural gas (therms)	**826.5**	**692.6**	959.2	797.1
Electric (kilowatt-hours)	**42,873.2**	**25,499.8**	34,405.7	20,374.0
Foreign exchange contracts (Canadian dollars)	**2.6**	**2.6**	4.2	4.2

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Gains (losses) related to non-hedge derivatives are recognized currently in earnings, as shown in the tables below:

(Millions)	Income Statement Presentation	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Natural gas contracts	Nonregulated revenue	**$ 7.4**	$ 6.2	**$ 11.4**	$ 14.3
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(0.3)**	(0.1)	**(1.5)**	(0.4)
Electric contracts	Nonregulated revenue	**9.0**	(2.9)	**(59.6)**	(3.9)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(0.7)**		**(1.4)**	0.2
Total		**$ 15.4**	$ 3.2	**$ (51.1)**	$ 10.2

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

In the next 12 months, pre-tax losses of $0.7 million and $5.9 million related to discontinued cash flow hedges of natural gas contracts and electric contracts, respectively, 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.

Fair Value Hedges

At PELLC, an interest rate swap designated as a fair value hedge was used to hedge changes in the fair value of $50.0 million of the $325.0 million Series A 6.9% notes. The interest rate swap and the notes were settled in January 2011.

Cash Flow Hedges

Prior to July 1, 2011, Integrys Energy Services designated derivative contracts such as futures, forwards, and swaps as accounting hedges under GAAP. These contracts are used to manage commodity price risk associated with customer contracts.

The tables below show the amounts related to cash flow hedges recorded in OCI and in earnings:

(Millions)	Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion) Three Months Ended June 30, 2011	Six Months Ended June 30, 2011
	$ (3.5)	$ (2.3)

Natural gas contracts				
Electric contracts		8.4		3.8
Total	$	4.9	$	1.5

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	Income Statement Presentation	Three Months Ended June 30				Six Months Ended June 30			
		2012		2011		2012		2011	
Settled/Realized									
Natural gas contracts	Nonregulated revenue	**$**		$	(0.7)	**$**		$	(9.3)
Electric contracts	Nonregulated revenue				8.3				4.2
Interest rate swaps *	Interest expense		**(0.3)**		(0.3)		**(0.6)**		(0.6)
Hedge Designation Discontinued									
Natural gas contracts	Nonregulated revenue								(0.3)
Interest rate swaps	Interest expense				(0.2)				(0.2)
Total		**$**	**(0.3)**	$	7.1	**$**	**(0.6)**	$	(6.2)

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

Gain (Loss) Recognized in Income on Derivative Instruments (Ineffective Portion and Amount Excluded from Effectiveness Testing)

(Millions)	Income Statement Presentation	Three Months Ended June 30 2011		Six Months Ended June 30 2011	
Natural gas contracts	Nonregulated revenue	$	(0.5)	$	0.3
Electric contracts	Nonregulated revenue		(0.6)		(0.3)
Total		$	(1.1)	$	

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NOTE 4 DISCONTINUED OPERATIONS

Holding Company and Other Segment

Discontinued operations were recorded primarily at the holding company and other segment. Uncertain tax positions included in our liability for unrecognized tax benefits were remeasured to better reflect how the underlying positions are resolving themselves in various taxing jurisdictions. We also effectively settled certain state income tax examinations in 2012. During the three months ended June 30, 2012 and 2011, we recorded $0.1 million and $0.9 million, respectively, of after-tax losses in discontinued operations. During the six months ended June 30, 2012 and June 30, 2011, we recorded a $1.8 million after-tax gain and a $0.9 million after-tax loss, respectively, in discontinued operations.

Integrys Energy Services

During the six months ended June 30, 2011, Integrys Energy Services recorded a $0.1 million after-tax gain in discontinued operations when contingent payments were earned related to the 2009 sale of its energy management consulting business.

NOTE 5 INVESTMENT IN ATC

Our electric transmission investment segment consists of WPS Investments LLC s ownership interest in ATC, which was approximately 34% at June 30, 2012. ATC is a for-profit, transmission-only company regulated by FERC. ATC owns, maintains, monitors, and operates electric transmission assets in portions of Wisconsin, Michigan, Minnesota, and Illinois.

The following table shows changes to our investment in ATC.

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	**2012**	**2011**	**2012**	**2011**
Balance at the beginning of period	**$ 446.9**	$ 422.7	**$ 439.4**	$ 416.3
Add: Equity in net income	**21.3**	19.9	**42.1**	39.1
Add: Capital contributions	**5.1**	2.5	**8.5**	5.9
Less: Dividends received	**16.9**	15.7	**33.6**	31.9
Balance at the end of period	**$ 456.4**	$ 429.4	**$ 456.4**	$ 429.4

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

(Millions)	Three Months Ended June 30 2012	2011	Six Months Ended June 30 2012	2011
Income statement data				
Revenues	**$ 152.1**	$ 138.2	**$ 299.8**	$ 277.8
Operating expenses	**71.7**	63.0	**141.3**	126.1
Other expense	**21.1**	19.5	**41.1**	41.8
Net income *	**$ 59.3**	$ 55.7	**$ 117.4**	$ 109.9

* As most income taxes are the responsibility of its members, ATC does not report a provision for its members income taxes in its income statements.

(Millions)	June 30, 2012	December 31, 2011
Balance sheet data		
Current assets	**$ 60.9**	$ 58.7
Noncurrent assets	**3,169.4**	3,053.7
Total assets	**$ 3,230.3**	$ 3,112.4
Current liabilities	**$ 208.3**	$ 298.5
Long-term debt	**1,550.0**	1,400.0
Other noncurrent liabilities	**90.7**	82.6
Members equity	**1,381.3**	1,331.3
Total liabilities and members equity	**$ 3,230.3**	$ 3,112.4

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NOTE 6 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. Due to seasonal requirements, PGL and NSG expect interim reductions in LIFO layers to be replenished by year end.

NOTE 7 GOODWILL AND OTHER INTANGIBLE ASSETS

We had no material changes to the carrying amount of goodwill during the six months ended June 30, 2012, and 2011. Annual impairment tests were completed at all of our reporting units that carried a goodwill balance in the second quarter of 2012, and no impairments resulted from these tests.

The identifiable intangible assets other than goodwill listed below are part of other current and long-term assets on the Balance Sheets.

(Millions)		**June 30, 2012**			**December 31, 2011**	
	Gross Carrying Amount	**Accumulated Amortization**	**Net Carrying Amount**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**
Amortized intangible assets						
Customer-related (1)	**$ 22.4**	**$ (13.9)**	**$ 8.5**	$ 34.5	$ (24.8)	$ 9.7
Electric contract assets (2)				7.8	(6.6)	1.2
Patents (3)	**7.2**	**(0.2)**	**7.0**	7.2		7.2
Compressed natural gas fueling contract assets (4)	**5.6**	**(0.8)**	**4.8**	5.6	(0.3)	5.3
Renewable energy credits (5)	**2.4**		**2.4**	2.8		2.8
Nonregulated easements (6)	**3.8**	**(0.8)**	**3.0**	3.8	(0.7)	3.1
Customer-owned equipment modifications (7)	**3.8**	**(0.4)**	**3.4**	3.6	(0.2)	3.4
Emission allowances (8)	**1.5**	**(0.1)**	**1.4**	1.7	(0.2)	1.5
Other	**0.9**	**(0.2)**	**0.7**	1.4	(0.3)	1.1
Total	**$ 47.6**	**$ (16.4)**	**$ 31.2**	$ 68.4	$ (33.1)	$ 35.3
Unamortized intangible assets						
MGU trade name	**$ 5.2**		**$ 5.2**	$ 5.2		$ 5.2
Trillium trade name	**3.5**		**3.5**	3.5		3.5
Pinnacle trade name	**1.5**		**1.5**	1.5		1.5
Total intangible assets	**$ 57.8**	**$ (16.4)**	**$ 41.4**	$ 78.6	$ (33.1)	$ 45.5

(1) Represents customer relationship assets associated with PELLC s former nonregulated retail natural gas and electric operations, MERC s nonutility ServiceChoice business, and Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) compressed natural gas fueling

operations. The remaining weighted-average amortization period for customer-related intangible assets at June 30, 2012, was approximately 10 years.

(2) Represents electric customer contracts acquired in exchange for risk management assets.

(3) Represents the fair value of patents at Pinnacle related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at June 30, 2012, was approximately 18 years.

(4) Represents the fair value of Trillium and Pinnacle compressed natural gas customer fueling contracts acquired in September 2011. The remaining amortization period at June 30, 2012, was approximately 9 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 June 30, 2012, of approximately 12 years.

(7) Relates to modifications to customer-owned equipment that allow the end-use customer of a pipeline to accept landfill gas. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at June 30, 2012, of approximately 12 years.

(8) Emission allowances do not have a contractual term or expiration date. If the EPA s Cross State Air Pollution Rule, which was stayed in December 2011, is reinstated, it will affect our ability to use certain existing emission allowances in the future. See Note 11, *Commitments and Contingencies,* for more information.

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Amortization expense recorded as a component of nonregulated cost of sales in the statements of income was $0.4 million for both the three months ended June 30, 2012, and 2011. Amortization expense for the six months ended June 30, 2012, and 2011, was $2.0 million and $0.7 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the three months ended June 30, 2012, and 2011, was $0.8 million and $0.9 million, respectively. Amortization expense for the six months ended June 30, 2012, and 2011, was $1.5 million and $1.7 million, respectively.

Amortization expense for the next five fiscal years is estimated to be:

	For the year ending December 31				
(Millions)	**2012**	**2013**	**2014**	**2015**	**2016**
Amortization recorded in nonregulated cost of sales	$ 5.1	$ 1.8	$ 1.4	$ 1.3	$ 1.1
Amortization recorded in depreciation and amortization expense	2.5	2.0	1.7	1.7	1.5

NOTE 8 SHORT-TERM DEBT AND LINES OF CREDIT

Our short-term borrowings were as follows:

(Millions, except percentages)	**June 30, 2012**	**December 31, 2011**
Commercial paper outstanding	**$ 279.0**	$ 303.3
Average discount rate on outstanding commercial paper	**0.37%**	0.31%

The commercial paper outstanding at June 30, 2012, had maturity dates ranging from July 2, 2012, through July 18, 2012.

The table below presents our average amount of short-term borrowings outstanding based on daily outstanding balances during the six months ended June 30:

(Millions)	**2012**	**2011**
Average amount of commercial paper outstanding	**$ 295.9**	$ 73.1
Average amount of short-term notes payable outstanding		7.3

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

(Millions)	Maturity	June 30, 2012	December 31, 2011
Revolving credit facility (Integrys Energy Group) (1)	04/23/13	**$**	$ 735.0
Revolving credit facility (Integrys Energy Group)	05/17/14	**275.0**	275.0
Revolving credit facility (Integrys Energy Group)	05/17/16	**200.0**	200.0
Revolving credit facility (Integrys Energy Group)	06/13/17	**635.0**	
Revolving credit facility (WPS) (1)	04/23/13		115.0
Revolving credit facility (WPS) (2)	06/12/13	**115.0**	
Revolving credit facility (WPS)	05/17/14	**135.0**	135.0
Revolving credit facility (PGL) (1)	04/23/13		250.0
Revolving credit facility (PGL)	06/13/17	**250.0**	
Total short-term credit capacity		**$ 1,610.0**	$ 1,710.0
Less:			
Letters of credit issued inside credit facilities		**$ 24.6**	$ 33.7
Commercial paper outstanding		**279.0**	303.3
Available capacity under existing agreements		**$ 1,306.4**	$ 1,373.0

(1) These credit facilities were terminated in June 2012.

(2) WPS requested approval from the PSCW to extend this facility through June 13, 2017.

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NOTE 9 LONG-TERM DEBT

(Millions)	June 30, 2012	December 31, 2011
WPS (1)	**$ 722.1**	$ 722.1
PGL (2)	**525.0**	525.0
NSG (3)	**74.5**	74.7
Integrys Energy Group (4)	**774.8**	774.8
Other term loan (5)	**27.0**	27.0
Total	**2,123.4**	2,123.6
Unamortized discount	**(1.4)**	(1.6)
Total debt	**2,122.0**	2,122.0
Less current portion	**(387.0)**	(250.0)
Total long-term debt	**$ 1,735.0**	$ 1,872.0

(1) In December 2012, WPS s 4.875% Senior Notes will mature. As a result, the $150.0 million balance of these notes was included in the current portion of long-term debt on our balance sheets.

In February 2013, WPS s 3.95% Senior Notes will mature. As a result, the $22.0 million balance of these notes was included in the current portion of long-term debt on our June 30, 2012 balance sheet.

(2) In May 2013, PGL s 4.625% Series NN-2 Fixed First and Refunding Mortgage Bonds will mature. As a result, the $75.0 million balance of these bonds was included in the current portion of long-term debt on our June 30, 2012 balance sheet.

(3) In April 2012, NSG bought back its $28.2 million of 5.00% Series M First Mortgage Bonds that were due December 1, 2028.

In the same month, NSG issued $28.0 million of 3.43% Series P First Mortgage Bonds. These bonds are due April 1, 2027.

In May 2013, NSG s 4.625% Series N-2 First Mortgage Bonds will mature. As a result, the $40.0 million balance of these bonds was included in the current portion of long-term debt on our June 30, 2012 balance sheet.

(4) In December 2012, our 5.375% 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 sheets.

(5) This loan has a floating interest rate that is reset weekly. At June 30, 2012, the interest rate was 0.18%. The loan is to be repaid by April 2021.

NOTE 10 INCOME TAXES

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

The table below shows our effective tax rates:

	Three Months Ended June 30		**Six Months Ended June 30**	
	2012	**2011**	**2012**	**2011**
Effective Tax Rate	**36.4%**	45.9%	**33.8%**	38.8%

Our effective tax rate for the three months ended June 30, 2012, did not differ materially from the federal statutory rate of 35%.

Our effective tax rate for the three months ended June 30, 2011, was higher than the federal tax rate of 35%. This difference was primarily due to an increase in our multistate income tax obligations in 2011, driven by tax law changes in Michigan and Wisconsin. We recorded $5.7 million of income tax expense in 2011 when we increased our deferred income tax liabilities related to these tax law changes. Other state income tax obligations also contributed to the higher effective tax rate.

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Our effective tax rate for the six months ended June 30, 2012, was lower than the federal statutory tax rate of 35%. This difference was partially due to the federal income tax benefit of tax credits related to wind production. We also settled certain state income tax examinations and remeasured uncertain tax positions included in our liability for unrecognized tax benefits in 2012. We decreased our provision for income taxes $5.5 million in 2012 related to the effective settlement and remeasurement of these positions. Other state income tax obligations partially offset the lower effective tax rate.

Our effective tax rate for the six months ended June 30, 2011, was higher than the federal statutory tax rate of 35%. This difference primarily related to state income tax obligations, including the $5.7 million impact of tax law changes in Michigan and Wisconsin discussed above.

During the six months ended June 30, 2012, we effectively settled certain state income tax examinations and remeasured uncertain tax positions that decreased our liability for unrecognized tax benefits by $8.3 million. We reduced the provision for income taxes related to the effective settlement and remeasurement as described above, of which a portion was reported as discontinued operations.

NOTE 11 COMMITMENTS AND CONTINGENCIES

Commodity 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 obligations to deliver energy to customers.

The purchase obligations described below were as of June 30, 2012.

- The electric utility segment had obligations of $1,154.2 million for either capacity or energy related to purchased power that extend through 2029, obligations of $189.7 million related to coal supply and transportation contracts that extend through 2016, and obligations of $5.4 million for other commodities that extend through 2013.
- The natural gas utility segment had obligations of $807.1 million related to natural gas supply and transportation contracts that extend through 2028.
- Integrys Energy Services had obligations of $207.4 million, primarily related to electricity and natural gas supply contracts that extend through 2020.
- We and our subsidiaries also had commitments of $539.2 million in the form of purchase orders issued to various vendors that relate to normal business operations, including construction projects.

Environmental

Clean Air Act (CAA) New Source Review Issues

Weston and Pulliam Plants:

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 continues to negotiate with the EPA on a possible resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In May 2010, WPS received from the Sierra Club a Notice of Intent (NOI) 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. WPS is working on a possible resolution with the Sierra Club and the EPA. We are currently unable to estimate the possible loss or range of loss related to this matter.

If it were settled or determined that historical projects at the Weston or Pulliam plants required either a state or federal CAA permit, WPS may, under the applicable statutes, be required to complete one or more of the following remedial steps:

- shut down the facility,
- install additional pollution control equipment and/or impose emission limitations, and/or
- conduct a supplemental beneficial environmental project.

In addition, WPS may also be required to pay a fine. Finally, under the CAA, citizen groups may pursue a claim.

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In response to the EPA s CAA enforcement initiative, several other utilities have already settled with the EPA, while others are in litigation. The fines, penalties, and costs of supplemental beneficial environmental projects associated with settlements involving comparably-sized facilities to Weston and Pulliam combined ranged between $6 million and $30 million. The regulatory interpretations upon which the lawsuits or settlements are based may change depending on future court decisions made in the pending litigation.

Columbia and Edgewater Plants:

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 WPS). The NOV alleges violations of the CAA s New Source Review requirements related to certain projects completed at those plants.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Columbia plant did not comply with the CAA. The case has been dismissed without prejudice as the parties continue to participate in settlement negotiations.

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. The case was stayed until July 15, 2012, and a request has been made by WP&L to further extend the stay and all deadlines, with an update to the court due by August 31, 2012, regarding the settlement negotiations with the Sierra Club, the EPA, and the joint owners of the Edgewater plant.

WPS, WP&L, and Madison Gas and Electric (Joint Owners), along with the EPA and the Sierra Club (collectively, the Parties) are exploring settlement options. The Joint Owners believe that the Parties have reached a tentative agreement on general terms to settle these air permitting violation claims and are negotiating a consent decree based upon those general terms, which are subject to change during the negotiations. Based upon the status of the current negotiations and a review of existing EPA consent decrees, WPS anticipates that the final consent decree could include the installation of emission control technology, changed operating conditions (including fuels other than coal and retirement of units), limitations on emissions, beneficial supplemental environmental projects, and a civil fine. Once the Parties agree to the final terms, the U.S. District court must approve the consent decree after a public comment process.

WPS cannot predict the final outcome of this matter because the Parties may be unable to reach a final agreement on the consent decree, the final terms of the consent decree may be different than currently anticipated, interveners could convince the court to make changes to the terms of the consent decree during the public comment process, or the court may not approve the final consent decree.

Any costs prudently incurred as a result of actions taken due to the consent decree are expected to be recoverable from customers. We are currently unable to estimate the possible loss or range of loss related to this matter.

Weston Air Permits

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, the WDNR, WPS, 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 and the Sierra Club to resolve this issue. We do not expect this matter to have a material impact on our financial statements.

Weston Title V Air Permit:

In November 2010, the WDNR provided a draft revised permit. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR. WPS and the WDNR continue to meet 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 permit, the WDNR intends to re-issue the draft permit for additional comments. On July 24, 2012, Clean Wisconsin filed suit against the WDNR alleging failure or delay in issuing the Weston 4 Title V permit. WPS is not a party to this litigation, but intends to intervene to protect its interests. We do not expect this matter to 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, Weston 1, Weston 2, and Weston 4, as well as one NOV for a clerical error involving pages missing from a quarterly report for Weston. Corrective actions have been taken for the events in the five NOVs. In December 2011, the WDNR dismissed two of the NOVs and referred the other three NOVs to the state Justice Department for enforcement. We do not expect this matter to have a material impact on our financial statements.

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Pulliam Title V Air Permit

The WDNR issued the renewal of the permit for the Pulliam plant in April 2009. In June 2010, the EPA issued an order directing the WDNR to respond to comments raised by the Sierra Club in its June 2009 Petition requesting the EPA to object to the permit.

WPS also challenged the permit in a contested case proceeding and Petition for Judicial Review. The Petition was dismissed in an order remanding the matter to the WDNR. In February 2011, the WDNR granted a contested case proceeding before an Administrative Law Judge on the issues raised by WPS, which included seeking averaging times in the emission limits in the permit. WPS participated in the contested case proceeding in October 2011. In December 2011, the Administrative Law Judge did not require the WDNR to insert averaging times, for which WPS had argued. WPS has decided not to appeal.

In October 2010, WPS received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA based on what the Sierra Club alleged to be an unreasonable delay in responding to the June 2010 order. WPS received notification that the Sierra Club filed suit against the EPA in April 2011. WPS intervened in the case as a necessary party to protect its interests. In February 2012, the WDNR sent a proposed permit and response to the EPA for a 45-day review, which allowed the parties to enter into a settlement agreement that has been entered by the court. On May 9, 2012, the Sierra Club filed another Petition requesting the EPA to again object to the proposed permit and response.

We are reviewing all of these matters, but we do not expect them to have a material impact on our financial statements.

Columbia Title V Air Permit

In October 2009, the EPA issued an order objecting to the permit renewal issued by the WDNR for the Columbia plant. The order determined that the WDNR did not adequately analyze whether a project in 2006 constituted a major modification that required a permit. The EPA s order directed the WDNR to resolve the objections within 90 days and terminate, modify, or revoke and reissue the permit accordingly.

In July 2010, WPS, along with its co-owners, received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA. The Sierra Club alleges that the EPA should assert jurisdiction over the permit because the WDNR failed to respond to the EPA s objection within 90 days.

In September 2010, the WDNR issued a draft construction permit and a draft revised Title V permit in response to the EPA s order. In November 2010, the EPA notified the WDNR that the EPA does not believe the WDNR s proposal is responsive to the order. In January 2011, the WDNR issued a letter stating that upon review of the submitted public comments, the WDNR has determined not to issue the draft permits that were proposed to respond to the EPA s order. In February 2011, the Sierra Club filed for a declaratory action, claiming that the EPA had to assert jurisdiction over the permits. In May 2011, the WDNR issued a second 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 has not addressed the EPA s objections to the Title V permit issues for the Columbia plant. WP&L has 90 days to comment on the EPA s proposal. If the EPA decides to require the submittal of an operation permit, it would be due within six months of the EPA s notice to WP&L. WP&L believes the previously issued Title V permit for the Columbia plant is still valid. 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, Chapter NR 446, requires a 40% reduction from the 2002 through 2004 baseline mercury emissions in Phase I, beginning January 1, 2010, through the end of 2014. In Phase II, which begins in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the 2002 through 2004 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 June 30, 2012, WPS estimates capital costs of approximately $2 million, which includes estimates for both wholly owned and jointly owned plants, to achieve the required Phase I and Phase II 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 rule that will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. 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:

The EPA issued the Clean Air Interstate Rule (CAIR) in 2005 in order to reduce sulfur dioxide and nitrogen oxide emissions from utility boilers located in 29 states, including Wisconsin, Michigan, Pennsylvania, and New York. In July 2008, the United States Court of Appeals (Court of Appeals) issued a decision vacating CAIR, which the EPA appealed. In December 2008, the Court of Appeals reinstated CAIR and directed the EPA

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to address the deficiencies noted in its previous ruling to vacate CAIR. In July 2011, the EPA issued a final CAIR replacement rule known as the Cross State Air Pollution Rule (CSAPR). The new rule was to become effective January 1, 2012; however, on December 30, 2011, the D.C. Circuit Court (Court) issued a decision that stayed the rule pending the Court s resolution of the petitions for review. The Court directed the EPA to implement CAIR during the stay period. In January 2012, a briefing and oral argument schedule was set. Oral arguments were held on April 13, 2012. In comparison to the CAIR rule, CSAPR, in the version that was stayed, significantly reduced the emission allowances allocated to our subsidiaries existing units for sulfur dioxide and nitrogen oxide in 2012, with a further reduction in 2014.

CSAPR also established new sulfur dioxide and nitrogen oxide emission allowances and did not allow carryover of the existing nitrogen oxide emission allowances allocated to WPS under CAIR. WPS did not acquire any CAIR nitrogen oxide emission allowances for 2012 and beyond other than those directly allocated to it, which were free. Sulfur dioxide emission allowances allocated under the Acid Rain Program will continue to be issued and surrendered independent of the stayed CSAPR emission allowance program. Thus, we do not expect any material impact on our financial statements as a result of being unable to carry over existing emission allowances.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule are considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they are in compliance with 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 are not warranted. The EPA has proposed that units in compliance with CSAPR, if the stay is lifted and CSAPR is reinstated, will also be considered in compliance with BART.

The Court may uphold CSAPR, invalidate CSAPR, or direct the EPA to make changes to CSAPR. In order to be in compliance with the stayed version of CSAPR, additional sulfur dioxide and nitrogen oxide controls would need to be installed, emission allowances would need to be purchased, and/or our subsidiaries would have to make other changes to how they operate their existing units. The installation of any necessary controls will be scheduled as part of WPS s long-term maintenance plan for its existing units; however, WPS does not currently believe it could meet the stayed CSAPR s sulfur dioxide and nitrogen oxide emission limits without purchasing additional emission allowances or changing how its existing units are operated. Due to the uncertainty surrounding the rule, we are currently unable to predict whether, or if, additional emission allowances would be available to purchase or how much it would cost to comply. We are also currently unable to predict whether CSAPR, or any future version of CSAPR, will cause WPS to idle or abandon certain units or impact the estimated useful lives of certain units. WPS expects to recover any future compliance costs in future rates. The 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 June 30, 2012, we estimated and accrued for $603.1 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 June 30, 2012, cash expenditures for environmental remediation not yet recovered in rates were $25.0 million. We recorded a regulatory asset of $628.1 million at June 30, 2012, which is net of insurance recoveries received of $60.0 million, related to the expected recovery of both cash expenditures and estimated future expenditures through rates.

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 WPS, MGU, PGL, and NSG. 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 rate recovery of such costs.

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NOTE 12 GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at June 30, 2012	Less Than 1 Year	Expiration 1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	**$ 618.6**	$ 397.6	$ 11.6	$ 209.4
Standby letters of credit (2)	**57.5**	29.3	28.1	0.1
Surety bonds (3)	**15.9**	15.9		
Other guarantees (4)	**42.8**	20.0		22.8
Total guarantees	**$ 734.8**	$ 462.8	$ 39.7	$ 232.3

(1) Consists of parental guarantees of $455.5 million to support the business operations of Integrys Energy Services; $108.3 million and $47.8 million, respectively, related to natural gas supply at MERC and MGU; and $5.0 million at IBS, and $2.0 million at UPPCO to support business operations. 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 $55.1 million issued to support Integrys Energy Services operations and $2.4 million issued to support UPPCO, WPS, MGU, NSG, MERC, PGL, and Pinnacle CNG Systems. These amounts are not reflected on our balance sheets.

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

(4) Consists of (a) $20.0 million related to the sale agreement for Integrys Energy Services United States wholesale electric marketing and trading business, which included a number of customary representations, warranties, and indemnification provisions. In addition, for a two-year period, counterparty payment default risk was retained with approximately 50% of the counterparties associated with the commodity contracts transferred in this transaction. An insignificant liability was recorded related to the fair value of this counterparty payment default risk;
(b) $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; (c) $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 (this amount is not reflected on the balance sheets); and (d) $7.8 million related to other indemnifications primarily for workers compensation coverage. These amounts are not reflected on our balance sheets.

We have provided total parental guarantees of $549.3 million on behalf of Integrys Energy Services as shown in the table below. Our exposure under these guarantees related to existing transactions at June 30, 2012, was approximately $248.3 million.

(Millions)		**June 30, 2012**
Guarantees supporting commodity transactions	**$**	**455.5**
Standby letters of credit		**55.1**
Surety bonds		**3.2**
Other		**35.5**
Total guarantees	**$**	**549.3**

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NOTE 13 EMPLOYEE BENEFIT PLANS

As of February 16, 2012, our defined benefit pension plans were closed to all new hires.

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

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended June 30		Six Months Ended June 30		Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2012	2011	2012	2011	2012	2011	2012	2011
Service cost	**$ 10.6**	$ 9.4	**$ 23.0**	$ 20.7	**$ 4.9**	$ 4.5	**$ 10.4**	$ 9.5
Interest cost	**19.2**	19.6	**39.0**	40.1	**7.1**	7.1	**14.3**	14.8
Expected return on plan assets	**(26.8)**	(25.3)	**(53.9)**	(50.0)	**(7.1)**	(5.7)	**(14.1)**	(10.7)
Amortization of transition obligation							**0.1**	0.1
Amortization of prior service cost (credit)	**1.3**	1.3	**2.5**	2.6	**(0.8)**	(1.1)	**(1.7)**	(2.0)
Amortization of net actuarial loss	**8.7**	4.3	**17.0**	9.0	**1.7**	0.9	**3.3**	2.0
Net periodic benefit cost	**$ 13.0**	$ 9.3	**$ 27.6**	$ 22.4	**$ 5.8**	$ 5.7	**$ 12.3**	$ 13.7

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. We contributed $172.2 million to our pension plans and $75.1 million to our other postretirement benefit plans during the six months ended June 30, 2012. We expect to contribute an additional $3.8 million to our pension plans and $39.1 million to our other postretirement benefit plans during the remainder of 2012, dependent upon various factors affecting us, including our liquidity position and tax law changes.

NOTE 14 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 six months ended June 30:

Three Months Ended June 30	Six Months Ended June 30

(Millions)	2012	2011	2012	2011
Performance stock rights	**$ 3.1**	$ 1.9	**$ 4.3**	$ 1.2
Restricted shares and restricted share units	**3.3**	3.1	**5.4**	5.3
Total stock-based compensation expense	**$ 6.4**	$ 5.0	**$ 9.7**	$ 6.5
Deferred income tax benefit	**$ 2.6**	$ 2.0	**$ 3.9**	$ 2.6

Compensation cost recognized for stock options during the three and six months ended June 30, 2012, and 2011, was not significant.

The total compensation cost capitalized for all awards during the three and six months ended June 30, 2012, and 2011, was not significant.

Stock Options

The fair value of stock option awards granted is estimated using a binomial lattice model. The expected term of option awards is calculated based on historical exercise behavior 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 its 10-year historical volatility. The following table shows the weighted-average fair value per stock option granted during the six months ended June 30, 2012, along with the assumptions incorporated into the valuation model:

	February 2012 Grant
Weighted-average fair value per option	**$6.30**
Expected term	**5 years**
Risk-free interest rate	**0.17% - 2.18%**
Expected dividend yield	**5.28%**
Expected volatility	**25%**

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A summary of stock option activity for the six months ended June 30, 2012, and information related to outstanding and exercisable stock options at June 30, 2012, 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, 2011	2,953,630	$ 48.09		
Granted	**279,535**	**53.24**		
Exercised	**(621,614)**	**45.59**		
Outstanding at June 30, 2012	**2,611,551**	**$ 49.24**	**6.04**	**$ 20.2**
Exercisable at June 30, 2012	**1,582,438**	**$ 50.08**	**4.92**	**$ 11.0**

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 at June 30, 2012. This is calculated as the difference between our closing stock price on June 30, 2012, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the six months ended June 30, 2012, and 2011, was $5.7 million and $1.7 million, respectively.

As of June 30, 2012, $2.0 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 1.9 years.

Cash received from option exercises during the six months ended June 30, 2012, and 2011, was $28.3 million and $1.7 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises for the six months ended June 30, 2012, and 2011, was $2.3 million and $0.7 million, respectively.

Performance Stock Rights

The fair values of performance stock rights were 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 was estimated using one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at June 30:

	2012
Risk-free interest rate	**0.32% - 1.27%**
Expected dividend yield	**5.28% - 5.34%**
Expected volatility	**21% - 36%**

A summary of the activity for the six months ended June 30, 2012, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value*
Outstanding at December 31, 2011	135,948	$ 46.18
Granted	**18,865**	**52.70**
Distributed	**(70,598)**	**42.93**
Adjustment for final payout	**(24,804)**	**42.93**
Outstanding at June 30, 2012	**59,411**	**53.48**

* 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 for awards that have not been elected for deferral into the deferred compensation plan six months prior to the completion of the performance period.

The weighted-average grant date fair value of performance stock rights awarded during the six months ended June 30, 2012, and 2011, was $52.70 and $49.21, per performance stock right, respectively.

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A summary of the activity for the six months ended June 30, 2012, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2011	186,215
Granted	**75,408**
Distributed	**(16,001)**
Adjustment for final payout	**(5,622)**
Outstanding at June 30, 2012	**240,000**

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of June 30, 2012, was $64.46 per performance stock right.

As of June 30, 2012, $4.6 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 1.3 years.

The total intrinsic value of performance stock rights distributed during the six months ended June 30, 2012, and 2011, was $4.7 million and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during the six months ended June 30, 2012, and 2011 was $1.9 million and $2.5 million, respectively.

Restricted Shares and Restricted Share Units

During the second quarter of 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at June 30, 2012.

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the six months ended June 30, 2012, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2011	497,722	$ 45.21
Granted	**188,346**	**53.24**
Dividend equivalents	**12,752**	**48.15**
Vested and released	**(194,207)**	**45.07**
Forfeited	**(2,554)**	**48.22**
Outstanding at June 30, 2012	**502,059**	**48.39**

As of June 30, 2012, $14.4 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.5 years.

The total intrinsic value of restricted share and restricted share unit awards vested and released during the six months ended June 30, 2012, and 2011, was $10.4 million and $6.6 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted shares and restricted share units during the six months ended June 30, 2012, and 2011, was $4.2 million and $2.6 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during the six months ended June 30, 2012, and 2011, was $53.24 and $49.40 per share, respectively.

NOTE 15 COMMON EQUITY

We had no changes to issued common stock during the six months ended June 30, 2012.

Beginning May 1, 2011, shares were purchased on the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans.

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The following table reconciles common shares issued and outstanding:

	June 30, 2012			December 31, 2011		
	Shares	Average Cost		Shares	Average Cost	
Common stock issued	**78,287,906**			78,287,906		
Less:						
Deferred compensation rabbi trust	**375,793**	**$**	**45.85***	382,971	$	44.54*
Total common shares outstanding	**77,912,113**			77,904,935		

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

Earnings Per Share

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. The calculations of diluted earnings per share for the three months ended June 30, 2012, and 2011, excluded 0.2 million and 0.8 million, respectively, out-of-the-money stock options that had an anti-dilutive effect. The calculations of diluted earnings per share for the six months ended June 30, 2012, and 2011, excluded 0.5 million and 0.8 million, respectively, out-of-the-money stock options that had an anti-dilutive effect. The following table reconciles our computation of basic and diluted earnings per share:

(Millions, except per share amounts)	Three Months Ended June 30 2012	2011	Six Months Ended June 30 2012	2011
Numerator:				
Net income from continuing operations	**$ 49.7**	$ 30.8	**$ 147.5**	$ 154.2
Discontinued operations, net of tax	**(0.1)**	(0.9)	**1.8**	(0.8)
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)	**(1.6)**	(1.6)
Net income attributed to common shareholders	**$ 48.8**	$ 29.1	**$ 147.7**	$ 151.8
Denominator:				
Average shares of common stock basic	**78.5**	78.7	**78.5**	78.5
Effect of dilutive securities				
Stock-based compensation	**0.6**	0.4	**0.6**	0.3
Deferred compensation	**0.2**		**0.2**	
Average shares of common stock diluted	**79.3**	79.1	**79.3**	78.8
Earnings per common share				

Basic	**$**	**0.62**	$	0.37	**$**	**1.88**	$	1.93
Diluted		**0.62**		0.37		**1.86**		1.93

Accumulated Other Comprehensive Loss

The following table shows the changes to our accumulated other comprehensive loss from December 31, 2011 to June 30, 2012:

	Cash Flow Hedges		Defined Benefit Pension Plans		Accumulated Other Comprehensive Income (Loss)	
Beginning balance at December 31, 2011	$	(11.5)	$	(31.0)	$	(42.5)
Current period other comprehensive income		**2.3**		**0.7**		**3.0**
Ending balance at June 30, 2012	**$**	**(9.2)**	**$**	**(30.3)**	**$**	**(39.5)**

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.

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The PSCW allows WPS to pay normal dividends on its common stock of no more than 103% of the previous year s common stock dividend. In addition, the PSCW currently requires WPS to maintain a calendar year average financial common equity ratio of 50.24% or higher. WPS must obtain PSCW approval if the payment of dividends would cause it to fall below this authorized level of common equity. 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.

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 June 30, 2012, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

As of June 30, 2012, total restricted net assets were approximately $1,405.7 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was approximately $117.2 million at June 30, 2012.

We also 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 six months ended June 30, 2012, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent

WPS	$ **52.8**	$	$ **40.0**
WPS Investments, LLC (1)	**33.5**		**8.5**
PGL (2)	**55.0**		
NSG (2)	**10.0**		
MERC		**18.0**	
IBS		**11.0**	**10.0**
MGU		**6.0**	
UPPCO		**7.5**	**8.5**
Total	$ **151.3**	$ **42.5**	$ **67.0**

(1) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At June 30, 2012, we had an 85.41% ownership interest, while WPS and UPPCO had a 12.03% and 2.56% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2012, all equity contributions to WPS Investments, LLC were made solely by us.

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

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NOTE 16 VARIABLE INTEREST ENTITIES

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. ITF and Paper Transport Inc. each own 50% 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 will be 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 June 30, 2012, and December 31, 2011, 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 Integrys PTI CNG Fuels LLC assets and liabilities included on our balance sheets were not significant.

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these agreements reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under the agreement. This contract expires in 2014. The other agreement contains a tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. This contract expires in 2016. As of June 30, 2012, and December 31, 2011, we had 517.5 megawatts of capacity available under these agreements. We evaluated both of these variable interest entities 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 contracts compared with the remaining lives of the plants and the fact that we do not have the power to direct the operations and maintenance of the facilities, we determined we are not the primary beneficiary of these variable interest entities. At June 30, 2012, and December 31, 2011, the assets and liabilities on the balance sheets that related to our involvement with these variable interest entities 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 these contracts. There is not a significant potential exposure to loss as a result of involvement with the variable interest entities.

NOTE 17 FAIR VALUE

Fair Value Measurements

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

	June 30, 2012			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ 1.8	$ 9.7	$	$ 11.5
Financial transmission rights (FTRs)			5.0	5.0
Petroleum product contracts				
Nonregulated Segments				
Natural gas contracts	29.1	71.0	6.8	106.9
Electric contracts	47.6	67.6	9.7	124.9

Foreign exchange contracts				0.2				0.2
Total Risk Management Assets	**$**	**78.5**	**$**	**148.5**	**$**	**21.5**	**$**	**248.5**
Risk Management Liabilities								
Utility Segments								
Natural gas contracts	$	0.7	$	31.2	$		$	31.9
FTRs						0.2		0.2
Petroleum product contracts		0.1						0.1
Coal contract						9.8		9.8
Nonregulated Segments								
Natural gas contracts		38.6		58.8		0.5		97.9
Electric contracts		64.9		120.9		24.4		210.2
Foreign exchange contracts		0.2						0.2
Total Risk Management Liabilities	**$**	**104.5**	**$**	**210.9**	**$**	**34.9**	**$**	**350.3**

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	December 31, 2011			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ 0.1	$ 9.1	$	$ 9.2
FTRs			2.3	2.3
Petroleum product contracts	0.1			0.1
Nonregulated Segments				
Natural gas contracts	50.7	104.1	8.7	163.5
Electric contracts	41.2	71.2	3.9	116.3
Foreign exchange contracts		0.2		0.2
Total Risk Management Assets	$ 92.1	$ 184.6	$ 14.9	$ 291.6
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$ 5.5	$ 39.2	$	$ 44.7
FTRs			0.1	0.1
Coal contract			6.9	6.9
Nonregulated Segments				
Natural gas contracts	55.0	105.6	0.4	161.0
Electric contracts	54.2	131.1	15.4	200.7
Foreign exchange contracts	0.2			0.2
Total Risk Management Liabilities	$ 114.9	$ 275.9	$ 22.8	$ 413.6

The risk management assets and liabilities listed in the tables include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. 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 Electric Contracts

	Three Months Ended June 30, 2012			Three Months Ended June 30, 2011		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$ (1.6)
Transfers into Level 2 from	**$**	**N/A**	**(3.8)**	$	N/A	(4.4)
Transfers into Level 3 from		**(3.8)**	**N/A**		0.1	N/A

Nonregulated Segments Electric Contracts

	Six Months Ended June 30, 2012			Six Months Ended June 30, 2011		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$ (1.6)
Transfers into Level 2 from	**$**	**N/A**	**(3.9)**	$	N/A	(6.8)

Transfers into Level 3 from		**(8.8)**	**N/A**		(5.3)	N/A

Nonregulated Segments Natural Gas Contracts

(Millions)	Three Months Ended June 30, 2012 Level 1	Level 2	Level 3	Three Months Ended June 30, 2011 Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**0.1**	$	N/A	0.2
Transfers into Level 3 from		**0.4**	**N/A**		0.1	N/A

Nonregulated Segments Natural Gas Contracts

(Millions)	Six Months Ended June 30, 2012 Level 1	Level 2	Level 3	Six Months Ended June 30, 2011 Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**1.4**	$	N/A	0.6
Transfers into Level 3 from		**2.8**	**N/A**			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 of the fair value hierarchy at the value as of the end of the reporting period.

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

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

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. Corrections to the fair value inputs are made if necessary.

The significant unobservable inputs used in the valuation that resulted in categorization within Level 3 were as follows at June 30, 2012. 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 derivative transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Average or Range**
Utility Segments					
FTRs	**$ 5.0**	**$ 0.2**	Market-based	Forward market prices ($/megawatt-month) (1)	188.59

Coal contract		**9.8**	Market-based	Forward market prices ($/ton) (2)	15.70	16.75
Nonregulated Segments						
Natural gas contracts	**6.8**	**0.5**	Market-based	Forward market prices ($/dekatherm) (3)	(0.08)	1.95
				Probability of default	11.62%	50.99%
[redacted]						

(1) Represents forward market prices developed using historical cleared pricing data from MISO used in the valuation of FTRs.

(2) Represents third-party forward market pricing used in the valuation of our coal contract.

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

(4) Represents the range of volatilities used in the valuation of options.

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

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.

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

Three Months Ended June 30, 2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	Total
Balance at the beginning of the period	$ 10.9	$ (21.9)	$ 0.9	$ (13.4)	$ (23.5)
Net realized and unrealized (losses) gains included in earnings	(4.9)	(0.2)	2.0		(3.1)
Net unrealized gains recorded as regulatory assets or liabilities			0.2	5.2	5.4
Purchases		1.0	4.9		5.9
Sales					
Settlements		6.4	(3.2)	(1.6)	1.6
Net transfers into Level 3	0.4	(3.8)			(3.4)
Net transfers out of Level 3	(0.1)	3.8			3.7
Balance at the end of the period	**$ 6.3**	**$ (14.7)**	**$ 4.8**	**$ (9.8)**	**$ (13.4)**
Net unrealized losses included in earnings related to instruments still held at the end of the period	**$ (4.9)**	**$ (0.2)**	**$**	**$**	**$ (5.1)**

Six Months Ended June 30, 2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	Total
Balance at the beginning of the period	$ 8.3	$ (11.5)	$ 2.2	$ (6.9)	$ (7.9)
Net realized and unrealized (losses) gains included in earnings	(0.8)	(7.9)	2.5		(6.2)
Net unrealized gains (losses) recorded as regulatory assets or liabilities			0.3	(0.6)	(0.3)
Purchases		2.1	4.9		7.0
Sales			(0.1)		(0.1)
Settlements	(2.6)	7.5	(5.0)	(2.3)	(2.4)
Net transfers into Level 3	2.8	(8.8)			(6.0)
Net transfers out of Level 3	(1.4)	3.9			2.5
Balance at the end of the period	**$ 6.3**	**$ (14.7)**	**$ 4.8**	**$ (9.8)**	**$ (13.4)**
Net unrealized losses included in earnings related to instruments still held at the end of the period	**$ (0.8)**	**$ (7.9)**	**$**	**$**	**$ (8.7)**

Three Months Ended June 30, 2011	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	Total
Balance at the beginning of the period	$ 18.5	$ (18.7)	$ 1.0	$ (4.9)	$ (4.1)
Net realized and unrealized gains (losses) included in earnings	3.7	(0.9)	(1.2)		1.6
Net unrealized (losses) gains recorded as regulatory assets or liabilities			(0.5)	1.1	0.6
Net unrealized gains included in other comprehensive loss		1.3			1.3
Purchases		1.6	5.9		7.5
Sales					
Settlements	(6.0)	1.3	0.3	(0.5)	(4.9)
Net transfers into Level 3	0.1	0.1			0.2
Net transfers out of Level 3	(0.2)	6.0			5.8

Balance at the end of the period	$	16.1	$	(9.3)	$	5.5	$	(4.3)	$	8.0
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$	3.7	$	(0.9)	$		$		$	2.8

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Six Months Ended June 30, 2011	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	Total
Balance at the beginning of the period	$ 30.2	$ (14.9)	$ 2.9	$ 2.5	$ 20.7
Net realized and unrealized gains (losses) included in earnings	7.7	(3.8)	(1.1)		2.8
Net unrealized losses recorded as regulatory assets or liabilities			(1.6)	(5.9)	(7.5)
Net unrealized gains included in other comprehensive loss		0.6			0.6
Purchases		1.9	5.9		7.8
Sales			(0.1)		(0.1)
Settlements	(21.2)	3.8	(0.5)	(0.9)	(18.8)
Net transfers into Level 3		(5.3)			(5.3)
Net transfers out of Level 3	(0.6)	8.4			7.8
Balance at the end of the period	$ 16.1	$ (9.3)	$ 5.5	$ (4.3)	$ 8.0
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 7.7	$ (3.8)	$	$	$ 3.9

Unrealized gains and losses included in earnings related to Integrys Energy Services risk management assets and liabilities are recorded through nonregulated revenue on the statements of income. Realized gains and losses on these same instruments are recorded in nonregulated revenue or nonregulated cost of sales, 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:

	June 30, 2012		December 31, 2011	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	**$ 2,122.0**	**$ 2,304.6**	$ 2,122.0	$ 2,281.5
Preferred stock	**51.1**	**52.9**	51.1	51.8

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, without considering the effect of third-party credit enhancements. 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 such item approximates fair value.

NOTE 18 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. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment, and there was no impairment during the periods ended June 30, 2012 and 2011. Capitalized direct-response advertising costs, net of accumulated amortization, totaled $5.3 million and $1.4 million as of June 30, 2012 and 2011, respectively.

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 $0.3 million and $1.3 million for the three and six month periods ended June 30, 2012, respectively. There was no amortization of direct-response advertising costs for the three and six month periods ended June 30, 2011.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. Other advertising expense was $1.4 million and $1.9 million for the three months ended June 30, 2012 and 2011, respectively. Other advertising expense was $3.2 million and $3.8 million for the six months ended June 30, 2012 and 2011, respectively.

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NOTE 19 REGULATORY ENVIRONMENT

Wisconsin

2013 Rate Case

On March 30, 2012, WPS filed an application with the PSCW to increase retail electric and natural gas rates $85.1 million and $12.8 million, respectively, with rates proposed to be effective January 1, 2013. The filing includes a request for a 10.30% return on common equity and a common equity ratio of 52.37% in WPS s regulatory capital structure. The proposed retail electric and natural gas rate increases for 2013 are primarily being driven by reduced sales, increased fuel costs to generate electricity, increased electric transmission costs, increased costs to maintain the integrity of natural gas pipelines, increased manufactured gas plant cleanup costs, and general inflation.

2012 Rates

On December 9, 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 exceed a 2% price variance from costs included in rates, they will be deferred for recovery or refund in a future rate proceeding. The rate order allows for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection, and reflects reduced contributions to the Focus on Energy Program. The rate order also allows for the deferral of direct Cross State Air Pollution Rule (CSAPR) compliance costs, including carrying costs. As of June 30, 2012, WPS deferred $3.0 million of costs related to CSAPR.

2011 Rates

On January 13, 2011, the PSCW issued a final written order for WPS authorizing an electric rate increase of $21.0 million, calculated on a per-unit basis. Although the rate order included a lower authorized return on common equity, lower rate base, and other reduced costs, which resulted in lower total revenues and margins, the rate order also projected lower total sales volumes, which led to a rate increase on a per-unit basis. The rate order also included a projected increase in customer counts that did not materialize, which impacts the decoupling calculation as it adjusts for differences between the actual and authorized margin per customer. The $21.0 million electric rate increase included $20.0 million of recovery of prior deferrals, the majority of which related to the recovery of the 2009 electric decoupling deferral. The $21.0 million excluded the impact of a $15.2 million estimated fuel refund (including carrying costs) from 2010. The PSCW rate order also required an $8.3 million decrease in natural gas rates, which included $7.1 million of recovery for the 2009 decoupling deferral. The new rates were effective January 14, 2011, and reflected a 10.30% return on common equity, down from a 10.90% return on common equity in the previous rate order, and a common equity ratio of 51.65% in WPS s regulatory capital structure.

The order also addressed the new Wisconsin electric fuel rule, which was finalized on March 1, 2011. The new fuel rule was effective retroactive to January 1, 2011. It requires the deferral of under or over-collections of fuel and purchased power costs that exceed a 2% price variance from the cost of fuel and purchased power included in rates. Under or over-collections deferred in the current year will be recovered or refunded in a future rate proceeding.

Michigan

2012 UPPCO Rates

On December 20, 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 UPPCO s regulatory capital structure. The settlement required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011. Additionally, the settlement agreement states that if UPPCO files a rate case in 2013, the earliest effective date for new final rates or self-implemented rates is January 1, 2014. 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.

2011 UPPCO Rates

On December 21, 2010, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $8.9 million, effective January 1, 2011. The new rates reflected a 10.30% return on common equity and a common equity ratio of 54.86% in

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UPPCO s regulatory capital structure. The order required UPPCO to terminate its uncollectibles expense tracking mechanism after the close of December 2010 business, but retained the decoupling mechanism.

Illinois

2013 Rate Cases

On July 31, 2012, PGL and NSG filed applications with the ICC to increase retail natural gas rates $78.3 million and $9.8 million, respectively, with rates expected to be effective in July 2013. PGL s request reflects a 10.75% return on common equity and a target common equity ratio of 50.00% in PGL s regulatory capital structure. NSG s request reflects a 10.75% return on common equity and a target common equity ratio of 50.00% in NSG s regulatory capital structure.

2012 Rates

On January 10, 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 reflect 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 reflect 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 appealed the ICC s approval of decoupling and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. On May 16, 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 be required if the Illinois Appellate Court (Court) finds that the ICC did not have the authority to approve decoupling and the Court orders a refund. As a result, the recovery of amounts related to decoupling is uncertain. Therefore, PGL and NSG reduced revenues by $13.2 million in the second quarter of 2012 related to decoupling amounts accrued for regulatory recovery as of March 31, 2012. Decoupling amounts accrued thereafter will have a reserve established against them equal to the amount accrued. As of June 30, 2012, a reserve of $16.1 million was recorded. PGL and NSG plan to defend the authority of the ICC to approve the decoupling mechanism. PGL and NSG still intend to file with the ICC for rate recovery, beginning in 2013, for amounts accrued related to decoupling since the decoupling mechanism is still in place.

Rider ICR

On January 21, 2010, the ICC approved a rider mechanism for PGL to earn a return on and recover the costs, above an annual baseline, of the AMRP through a special charge on customers bills, known as Rider ICR. The AMRP is a 20-year project that began in 2011 under which PGL is replacing its cast iron and ductile iron pipes with steel and polyethylene pipes. In June 2010, the ICC issued a rehearing order approving PGL s proposed baseline of $45.28 million with an annual escalation factor. Recovery of costs for the AMRP became effective on April 1, 2011. On September 30, 2011, the Illinois Appellate Court, First District, reversed the ICC s approval of Rider ICR, concluding it was improper single issue ratemaking. PGL and the ICC filed for leave to appeal with the Illinois Supreme Court, but their requests were denied. In March 2012, the

Illinois Appellate Court remanded the matter to the ICC for further proceeding consistent with its September 30, 2011 decision. On June 27, 2012, the ICC issued a remand order requiring that PGL refund $2.3 million, over a nine-month period beginning in July 2012, in the form of a refund and reconciliation adjustment. The refund amount of $2.3 million was included in PGL s regulatory liabilities as of June 30, 2012.

Minnesota

2011 Rates

On July 13, 2012, the MPUC approved a written order for MERC authorizing a retail natural gas rate increase of $11.0 million, which will likely become effective in the fourth quarter of 2012. The new rates reflect a 9.70% return on common equity and a common equity ratio of 50.48% in MERC s regulatory capital structure. In addition, the order set recovery of MERC s 2011 test-year pension expense at 2010 levels. MERC filed an appeal related to certain aspects of the rate order, including the pension expense. The effective date of the rate order is pending based on the appeal process. The MPUC also approved a decoupling mechanism for MERC on a three-year trial basis. The decoupling mechanism becomes effective when final rates are implemented.

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.

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Integrys Energy Services initially expensed the majority of the total $19.2 million of billings received for the 16-month transitional period. The remaining amount was considered probable of recovery due to inconsistencies between the FERC s SECA order and the transmission owners compliance filings. Integrys Energy Services protested the FERC s order, and in August 2006, the Administrative Law Judge hearing the case issued an Initial Decision that was in substantial agreement with all of Integrys Energy Services positions. In May 2010, the FERC ruled favorably for Integrys Energy Services on two issues, but reversed the rulings of the Initial Decision on nearly every other substantive issue. Integrys Energy Services and numerous other parties filed for rehearing of the FERC s order. On September 30, 2011, the FERC denied rehearing of its order on the Initial Decision. The FERC has not yet issued an order on the compliance filings made by transmission owners. Integrys Energy Services has appealed the adverse FERC decision to the U.S. Court of Appeals for the D.C. Circuit.

As of June 30, 2012, Integrys Energy Services expected to receive future refunds of $3.8 million. Once the orders on compliance filings are issued, refunds will be made. Any refunds will include interest for the period from payment to refund.

NOTE 20 SEGMENTS OF BUSINESS

At June 30, 2012, 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 with operations in Wisconsin, Michigan, Minnesota, and Illinois.
- Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas to commercial, industrial, and residential customers 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 and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS. The operations of ITF were included in this segment beginning on September 1, 2011, when we acquired Trillium USA and Pinnacle CNG Systems.

The tables below present information related to our reportable segments:

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

Three Months Ended June 30, 2012								
External revenues	$ 251.8	$ 311.8	$	$ 563.6	$ 271.1	$ 7.2	$	$ 841.9
Intersegment revenues	1.9			1.9	0.3	0.5	(2.7)	
Depreciation and amortization expense	32.7	22.1		54.8	3.0	5.6	(0.2)	63.2
Earnings from equity method investments			21.3	21.3	0.6	0.3		22.2
Miscellaneous income (expense)	0.3	0.5		0.8	(0.1)	5.0	(4.0)	1.7
Interest expense	11.4	9.0		20.4	0.7	12.8	(4.0)	29.9
Provision (benefit) for income taxes	(7.4)	12.7	8.2	13.5	18.6	(3.7)		28.4
Net income (loss) from continuing operations	(11.0)	21.5	13.1	23.6	30.9	(4.8)		49.7
Discontinued operations						(0.1)		(0.1)
Preferred stock dividends of subsidiary	(0.2)	(0.6)		(0.8)				(0.8)
Net income (loss) attributed to common shareholders	(11.2)	20.9	13.1	22.8	30.9	(4.9)		48.8

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(Millions)	Regulated Operations Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended June 30, 2011								
External revenues	$ 361.2	$ 309.6	$	$ 670.8	$ 336.2	$ 3.8	$	$ 1,010.8
Intersegment revenues	2.8	5.8		8.6	0.1	0.3	(9.0)	
Depreciation and amortization expense	31.3	22.0		53.3	3.2	5.9	(0.2)	62.2
Earnings from equity method investments			19.9	19.9		0.4		20.3
Miscellaneous income	1.3	0.2		1.5	0.4	5.6	(6.2)	1.3
Interest expense	12.2	11.8		24.0	0.5	13.9	(6.2)	32.2
Provision for income taxes	0.9	10.8	7.9	19.6	5.1	1.4		26.1
Net income (loss) from continuing operations	1.3	18.9	12.0	32.2	6.0	(7.4)		30.8
Discontinued operations						(0.9)		(0.9)
Preferred stock dividends of subsidiary	(0.1)	(0.7)		(0.8)				(0.8)
Net income (loss) attributed to common shareholders	1.2	18.2	12.0	31.4	6.0	(8.3)		29.1

(Millions)	Regulated Operations Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Six Months Ended June 30, 2012								
External revenues	**$ 915.8**	**$ 618.8**	**$**	**$ 1,534.6**	**$ 543.9**	**$ 14.7**	**$**	**$ 2,093.2**
Intersegment revenues	**3.6**			**3.6**	**0.5**	**1.2**	**(5.3)**	
Depreciation and amortization expense	**65.1**	**44.1**		**109.2**	**5.9**	**11.1**	**(0.3)**	**125.9**
Earnings from equity method investments			**42.1**	**42.1**	**0.7**	**0.5**		**43.3**
Miscellaneous income	**0.5**	**0.6**		**1.1**	**0.5**	**10.7**	**(8.2)**	**4.1**
Interest expense	**23.4**	**18.2**		**41.6**	**1.3**	**25.7**	**(8.2)**	**60.4**
Provision (benefit) for income taxes	**44.1**	**22.9**	**15.7**	**82.7**	**5.7**	**(13.2)**		**75.2**
Net income (loss) from continuing operations	**67.7**	**46.5**	**26.4**	**140.6**	**10.8**	**(3.9)**		**147.5**
Discontinued operations						**1.8**		**1.8**
Preferred stock dividends of subsidiary	**(0.3)**	**(1.3)**		**(1.6)**				**(1.6)**

Net income (loss) attributed to common shareholders	**67.4**	**45.2**	**26.4**	**139.0**	**10.8**	**(2.1)**	**147.7**

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(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
Six Months Ended June 30, 2011								
External revenues	$ 1,212.5	$ 627.0	$	$ 1,839.5	$ 791.4	$ 7.0	$	$ 2,637.9
Intersegment revenues	4.9	11.0		15.9	0.4	0.7	(17.0)	
Depreciation and amortization expense	62.5	44.1		106.6	6.5	11.7	(0.3)	124.5
Earnings from equity method investments			39.1	39.1		0.6		39.7
Miscellaneous income	1.4	0.5		1.9	1.3	11.6	(11.7)	3.1
Interest expense	24.6	23.8		48.4	1.0	29.3	(11.7)	67.0
Provision (benefit) for income taxes	53.1	22.6	15.7	91.4	10.7	(4.3)		97.8
Net income (loss) from continuing operations	78.7	44.6	23.4	146.7	16.7	(9.2)		154.2
Discontinued operations					0.1	(0.9)		(0.8)
Preferred stock dividends of subsidiary	(0.3)	(1.3)		(1.6)				(1.6)
Net income (loss) attributed to common shareholders	78.4	43.3	23.4	145.1	16.8	(10.1)		151.8

NOTE 21 NEW ACCOUNTING PRONOUNCEMENTS

Recently Issued Accounting Guidance Not Yet Effective

ASU 2011-11, Disclosures about Offsetting Assets and Liabilities, was issued in December 2011. The guidance requires enhanced disclosures about offsetting and related arrangements. This guidance is effective for our reporting period ending March 31, 2013. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

ASU 2012-02, Testing Indefinite-Lived Intangible Assets for Impairment, was issued in July 2012. The amendments give companies an option to first perform a qualitative assessment to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. If a company concludes that this is the case, the fair value of the indefinite-lived intangible asset must be determined, and a quantitative impairment test is required. Otherwise, a company can bypass the quantitative impairment test. This guidance is effective for our reporting period ending March 31, 2013, and is not expected to have a significant impact on our financial statements.

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

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2011.

SUMMARY

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

RESULTS OF OPERATIONS

Earnings Summary

	Three Months Ended	Change in	Six Months Ended