INTEGRYS ENERGY GROUP, INC.
Form 10-Q
August 04, 2011
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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, 2011

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	IRS 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
July 28, 2011

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INTEGRYS ENERGY GROUP, INC.

QUARTERLY REPORT ON FORM 10-Q

For the Quarter Ended June 30, 2011

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EXHIBITS FILED WITH THIS 10-Q:

12	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101*	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended June 30, 2011, filed on August 3, 2011, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Balance Sheets, (iii) the Condensed Consolidated Statements of Cash Flows, (iv) the Condensed Notes To Financial Statements, and (v) document and entity information

* In accordance with Rule 406T of Regulation S-T, the information in these exhibits shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such filing.

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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
BACT	Best Available Control Technology
CAA	Clean Air Act
CSAPR	Cross State Air Pollution Rule
EEP	Enhanced Efficiency Program
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FTRs	Financial Transmission Rights
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
ICR	Infrastructure Cost Recovery
IRS	United States Internal Revenue Service
ITC	Investment Tax Credit
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
NOI	Notice of Intent
NOV	Notice of Violation
NSG	North Shore Gas Company

OCI	Other Comprehensive Income
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WDNR	Wisconsin Department of Natural Resources
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

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Forward-Looking Statements

In this report, we make statements concerning expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. Such statements are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are subject to assumptions and uncertainties; therefore, actual results may differ materially from those expressed or implied by such forward-looking 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 include, among other things, statements concerning management s expectations and projections regarding earnings, regulatory matters, fuel and natural gas costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, environmental expenditures, liquidity and capital resources, trends, estimates, completion of construction projects, and other matters.

Forward-looking statements involve a number of risks and uncertainties. Some risks that could cause results to differ from any forward-looking statement include those described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010, as may be amended or supplemented in Part II, Item 1A of our subsequently filed Quarterly Reports on Form 10-Q (including this report). Other risks and uncertainties include, but are not limited to:

- Resolution of pending and future rate cases and negotiations (including the recovery of deferred costs) and other regulatory decisions impacting our regulated businesses;
- The individual and cumulative impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric and natural gas utility industries; financial reform; health care reform; changes in environmental and other regulations, including but not limited to, greenhouse gas emissions, other environmental regulations impacting coal-fired generation facilities, energy efficiency mandates, renewable energy standards, and reliability standards; and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- Current and future litigation and regulatory proceedings, enforcement actions or inquiries, including but not limited to, manufactured gas plant site cleanup, third-party intervention in permitting and licensing projects, compliance with CAA requirements at generation plants, and prudence and reconciliation of costs recovered in revenues through automatic gas cost recovery mechanisms;
- The impacts of changing financial market conditions, credit ratings, and interest rates on the liquidity and financing efforts of us and our subsidiaries;
- 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;
- Resolution of audits or other tax disputes with the IRS and various state, local, and Canadian revenue agencies;
- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;
- The retention of market-based rate authority;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- Investment performance of employee benefit plan assets and the related impact on future funding requirements;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- Effects of and changes in political and legal developments, as well as economic conditions and the related impact on customer demand, including the ability to attract and retain customers for Integrys Energy Services and to adequately forecast energy usage 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 direct or indirect effects of terrorist incidents, natural disasters, or responses to such events;

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- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the ability to recover costs from customers in rates associated with the use of those strategies and financial and derivative instruments;
- 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;
- Customer usage, weather, and other natural phenomena;
- The use of tax credit and loss carryforwards;
- Contributions to earnings by non-consolidated equity method and other investments, which may vary from projections;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file from time to time 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 2011	2010	Six Months Ended June 30 2011	2010
Utility revenues	**$ 670.8**	$ 610.8	**$ 1,839.5**	$ 1,867.4
Nonregulated revenues	**340.0**	404.0	**798.4**	1,050.8
Total revenues	**1,010.8**	1,014.8	**2,637.9**	2,918.2
Utility cost of fuel, natural gas, and purchased power	**305.2**	250.9	**965.9**	992.4
Nonregulated cost of fuel, natural gas, and purchased power	**291.0**	315.5	**695.0**	955.1
Operating and maintenance expense	**260.4**	242.3	**523.9**	510.4
Restructuring expense	**0.8**	6.5	**2.0**	9.2
Net (gain) loss on Integrys Energy Services dispositions related to strategy change	**(0.1)**	(25.0)	**(0.2)**	14.8
Depreciation and amortization expense	**62.2**	67.8	**124.5**	131.9
Taxes other than income taxes	**23.8**	20.6	**50.6**	48.8
Operating income	**67.5**	136.2	**276.2**	255.6
Miscellaneous income	**21.6**	24.4	**42.8**	44.8
Interest expense	**(32.2)**	(36.6)	**(67.0)**	(76.0)
Other expense	**(10.6)**	(12.2)	**(24.2)**	(31.2)
Income before taxes	**56.9**	124.0	**252.0**	224.4
Provision for income taxes	**26.1**	44.4	**97.8**	94.4
Net income from continuing operations	**30.8**	79.6	**154.2**	130.0
Discontinued operations, net of tax	**(0.9)**		**(0.8)**	0.1
Net income	**29.9**	79.6	**153.4**	130.1
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)	**(1.6)**	(1.6)
Noncontrolling interest in subsidiaries		0.3		0.3
Net income attributed to common shareholders	**$ 29.1**	$ 79.1	**$ 151.8**	$ 128.8
Average shares of common stock				
Basic	**78.7**	77.4	**78.5**	77.2
Diluted	**79.1**	77.9	**78.8**	77.6
Earnings (loss) per common share (basic)				
Net income from continuing operations	**$ 0.38**	$ 1.02	**$ 1.94**	$ 1.67

Discontinued operations, net of tax		**(0.01)**				**(0.01)**		
Earnings per common share (basic)	**$**	**0.37**	$	1.02	**$**	**1.93**	$	1.67
Earnings (loss) per common share (diluted)								
Net income from continuing operations	**$**	**0.38**	$	1.02	**$**	**1.94**	$	1.66
Discontinued operations, net of tax		**(0.01)**				**(0.01)**		
Earnings per common share (diluted)	**$**	**0.37**	$	1.02	**$**	**1.93**	$	1.66
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 BALANCE SHEETS (Unaudited)

(Millions)	June 30 2011	December 31 2010
Assets		
Cash and cash equivalents	$ 211.4	$ 179.0
Collateral on deposit	36.2	33.3
Accounts receivable and accrued unbilled revenues, net of reserves of $47.2 and $41.9, respectively	577.3	832.1
Inventories	161.6	247.9
Assets from risk management activities	165.3	236.9
Regulatory assets	69.7	117.9
Deferred income taxes	70.6	67.7
Prepaid taxes	300.4	269.9
Other current assets	73.0	65.7
Current assets	1,665.5	2,050.4
Property, plant, and equipment, net of accumulated depreciation of $2,968.8 and $2,900.2, respectively	5,018.0	5,013.4
Regulatory assets	1,490.2	1,495.1
Assets from risk management activities	70.2	89.4
Goodwill	642.5	642.5
Other long-term assets	544.2	526.0
Total assets	$ 9,430.6	$ 9,816.8
Liabilities and Equity		
Short-term debt	$ 57.6	$ 10.0
Current portion of long-term debt	150.9	476.9
Accounts payable	388.2	453.0
Liabilities from risk management activities	190.9	289.6
Accrued taxes	73.7	90.2
Regulatory liabilities	62.4	75.7
Temporary LIFO liquidation credit	54.8	
Other current liabilities	199.2	262.4
Current liabilities	1,177.7	1,657.8
Long-term debt	2,131.6	2,161.6
Deferred income taxes	1,008.9	860.5
Deferred investment tax credits	44.8	45.2
Regulatory liabilities	324.2	316.2
Environmental remediation liabilities	640.3	643.9
Pension and other postretirement benefit obligations	519.8	603.4
Liabilities from risk management activities	80.9	99.7
Asset retirement obligations	329.3	320.9
Other long-term liabilities	139.8	150.6
Long-term liabilities	5,219.6	5,202.0
Commitments and contingencies		
	78.3	77.8

Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,918,698 shares outstanding				
Additional paid-in capital		**2,561.7**		2,540.4
Retained earnings		**396.7**		350.8
Accumulated other comprehensive loss		**(38.2)**		(44.7)
Shares in deferred compensation trust		**(16.4)**		(18.5)
Total common shareholders equity		**2,982.1**		2,905.8
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		**51.1**		51.1
Noncontrolling interest in subsidiaries		**0.1**		0.1
Total liabilities and equity	**$**	**9,430.6**	$	9,816.8

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)

	Six Months Ended June 30	
(Millions)	**2011**	**2010**
Operating Activities		
Net income	**$ 153.4**	$ 130.1
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	**0.8**	(0.1)
Depreciation and amortization expense	**124.5**	131.9
Recoveries and refunds of regulatory assets and liabilities	**23.9**	16.1
Net unrealized gains on nonregulated energy contracts	**(9.3)**	(15.6)
Bad debt expense	**20.3**	26.3
Pension and other postretirement expense	**36.1**	33.8
Pension and other postretirement contributions	**(108.9)**	(61.7)
Deferred income taxes and investment tax credits	**126.9**	64.5
(Gain) loss on sale of assets	**(0.5)**	13.5
Equity income, net of dividends	**(7.8)**	(7.2)
Other	**12.7**	11.8
Changes in working capital		
Collateral on deposit	**(3.0)**	177.5
Accounts receivable and accrued unbilled revenues	**236.7**	339.3
Inventories	**86.0**	140.4
Other current assets	**(12.1)**	(2.7)
Accounts payable	**(54.1)**	(104.5)
Temporary LIFO liquidation credit	**54.8**	45.0
Other current liabilities	**(92.2)**	(180.0)
Net cash provided by operating activities	**588.2**	758.4
Investing Activities		
Capital expenditures	**(114.5)**	(122.8)
Proceeds from the sale or disposal of assets	**3.3**	59.8
Capital contributions to equity method investments	**(11.0)**	(5.1)
Other	**(0.3)**	2.7
Net cash used for investing activities	**(122.5)**	(65.4)
Financing Activities		
Short-term debt, net	**57.6**	(199.6)
Redemption of notes payable	**(10.0)**	
Proceeds from sale of borrowed natural gas		21.3
Purchase of natural gas to repay natural gas loans		(6.0)
Repayment of long-term debt	**(355.2)**	(116.1)
Payment of dividends		
Preferred stock of subsidiary	**(1.6)**	(1.6)
Common stock	**(100.4)**	(92.7)
Issuance of common stock	**4.9**	18.8
Payments made on derivative contracts related to divestitures classified as financing activities	**(20.2)**	(118.5)
Other	**(8.4)**	(10.0)
Net cash used for financing activities	**(433.3)**	(504.4)

Change in cash and cash equivalents - continuing operations		**32.4**		188.6
Change in cash and cash equivalents - discontinued operations				
Net cash provided by investing activities				0.1
Net change in cash and cash equivalents		**32.4**		188.7
Cash and cash equivalents at beginning of period		**179.0**		44.5
Cash and cash equivalents at end of period	**$**	**211.4**	$	233.2

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, 2011

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 balance sheets, condensed consolidated statements of income, and condensed consolidated statements of cash flows, unless otherwise noted. In this report, when we refer to us, we, our, or ours, we are referring to Integrys Energy Group, Inc.

Our financial statements have been prepared pursuant to 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 notes in our Annual Report on Form 10-K for the year ended December 31, 2010.

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

Reclassifications

We reclassified $127.2 million reported in other current assets at December 31, 2010, to prepaid taxes to match the current period presentation on the balance sheet.

Change in Accounting Policy

During the fourth quarter of 2010, we changed our method of accounting for ITCs from the flow-through method to the deferral method. Under the flow-through method, we reduced the provision for income taxes by the amount of the ITC in the year in which the credit was received. Under the deferral method, we record the ITC as a deferred credit and amortize such credit as a reduction to the provision for income taxes over the life of the asset that generated the ITC.

The change in accounting policy only impacted financial statement line items for Integrys Energy Services. The application of regulatory requirements resulted in deferral of such credits for the regulated utility segments.

The following table reflects the impacts of the change in accounting policy on our financial statements:

(Millions, except per share data)	For the Three Months Ended June 30, 2010 As Originally Reported	Adjustments	Retrospectively Adjusted
Statements of Income			
Depreciation and amortization expense	$ 67.9	$ (0.1)	$ 67.8
Provision for income taxes	44.5	(0.1)	44.4
Net income from continuing operations	79.4	0.2	79.6
Net income	79.4	0.2	79.6
Net income attributed to common shareholders	78.9	0.2	79.1
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$ 1.01	$ 0.01	$ 1.02
Earnings per common share (diluted)	1.01	0.01	1.02

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(Millions, except per share data)	For the Six Months Ended June 30, 2010 As Originally Reported	Adjustments	Retrospectively Adjusted
Statements of Income			
Depreciation and amortization expense	$ 132.1	$ (0.2)	$ 131.9
Provision for income taxes	94.6	(0.2)	94.4
Net income from continuing operations	129.6	0.4	130.0
Net income	129.7	0.4	130.1
Net income attributed to common shareholders	128.4	0.4	128.8
Earnings (loss) per common share (basic)			
Net income from continuing operations	$ 1.66	$ 0.01	$ 1.67
Earnings per common share (basic)	1.66	0.01	1.67
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$ 1.65	$ 0.01	$ 1.66
Earnings per common share (diluted)	1.65	0.01	1.66

The change in accounting policy for ITCs also impacted previously reported amounts in the Statements of Cash Flows. Although there was no overall impact on net cash provided by operating activities, we adjusted certain line items classified within this category to reflect the amounts included in the table above. These line items were: net income, depreciation and amortization expense, and deferred income taxes and investment tax credits.

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:

(Millions)	Six Months Ended June 30 2011	2010
Cash paid for interest	**$ 71.1**	$ 70.7
Cash paid for income taxes	**3.2**	42.4

Significant noncash transactions were:

(Millions)	Six Months Ended June 30 2011	2010
Construction costs funded through accounts payable	**$ 23.7**	$ 16.3
Equity issued for stock-based compensation plans	**15.8**	3.0
Equity issued for reinvested dividends	**5.4**	11.2

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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, 2011 Assets from Risk Management Activities	June 30, 2011 Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ **2.4**	$ **12.5**
Natural gas contracts	Long-term	**1.6**	**1.0**
FTRs	Current	**5.6**	**0.1**
Petroleum product contracts	Current	**0.7**	
Coal contract	Current		**1.3**
Coal contract	Long-term		**3.0**
Cash flow hedges			
Natural gas contracts	Current		**0.5**
Natural gas contracts	Long-term		**0.1**
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**79.2**	**70.7**
Natural gas contracts	Long-term	**44.5**	**38.9**
Electric contracts	Current	**67.0**	**88.6**
Electric contracts	Long-term	**20.2**	**30.3**
Foreign exchange contracts	Current	**0.9**	**0.9**
Foreign exchange contracts	Long-term	**0.3**	**0.3**
Cash flow hedges			
Natural gas contracts	Current	**0.6**	**4.0**
Natural gas contracts	Long-term		**0.8**
Electric contracts	Current	**8.9**	**12.3**
Electric contracts	Long-term	**3.6**	**6.5**
	Current	**165.3**	**190.9**
	Long-term	**70.2**	**80.9**
Total		$ **235.5**	$ **271.8**

* 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, 2010 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 2.2	$ 23.6
Natural gas contracts	Long-term	1.6	1.4
FTRs	Current	3.1	0.2
Petroleum product contracts	Current	0.6	
Coal contract	Current		1.2
Coal contract	Long-term	3.7	
Cash flow hedges			
Natural gas contracts	Current		1.0
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	132.0	113.8
Natural gas contracts	Long-term	62.3	57.7
Electric contracts	Current	85.7	122.0
Electric contracts	Long-term	16.5	30.3
Foreign exchange contracts	Current	1.2	1.2
Foreign exchange contracts	Long-term	0.3	0.3
Fair value hedges			
Interest rate swaps	Current	0.9	
Cash flow hedges			
Natural gas contracts	Current	1.6	9.2
Natural gas contracts	Long-term	0.1	0.9
Electric contracts	Current	9.6	17.4
Electric contracts	Long-term	4.9	9.1
	Current	236.9	289.6
	Long-term	89.4	99.7
Total		$ 326.3	$ 389.3

* 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.

The following table shows our cash collateral positions:

(Millions)	June 30, 2011	December 31, 2010
Cash collateral provided to others	**$ 36.2**	$ 33.3
Cash collateral received from others *	**3.4**	4.5

* Reflected in other current liabilities on the Balance Sheets.

Certain of our derivative and nonderivative commodity instruments contain provisions that could require adequate assurance in the event of a material adverse 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, 2011**	**December 31, 2010**
Integrys Energy Services	**$ 130.4**	$ 219.5
Utility segments	**13.3**	22.1

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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, 2011	December 31, 2010
Collateral that would have been required:		
Integrys Energy Services	**$ 204.9**	$ 295.7
Utility segments	**8.0**	14.1
Collateral already satisfied:		
Integrys Energy Services Letters of credit	**16.0**	56.9
Collateral remaining:		
Integrys Energy Services	**188.9**	238.8
Utility segments	**8.0**	14.1

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, 2011		December 31, 2010	
	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**660.6**	**N/A**	979.9	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**11,076.8**	N/A	5,882.5
Petroleum products (barrels)	**43,911.0**	**N/A**	71,827.0	N/A
Coal contract (millions of tons)	**4.5**	**N/A**	4.9	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 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Natural gas contracts	Balance Sheet	Regulatory assets (current)	**$ 2.2**	$ 21.6	**$ 13.4**	$ (4.8)
Natural gas contracts	Balance Sheet	Regulatory assets (long-term)	**(1.4)**	2.8	**0.2**	(2.4)
Natural gas contracts	Balance Sheet	Regulatory liabilities (current)		0.1	**(0.1)**	(0.1)

Natural gas contracts	Balance Sheet	Regulatory liabilities (long-term)	**(0.1)**			
Natural gas contracts	Income Statement	Utility cost of fuel, natural gas, and purchased power		0.1	**0.1**	0.1
FTRs	Balance Sheet	Regulatory assets (current)	**(1.6)**	(1.5)	**(1.5)**	(0.6)
FTRs	Balance Sheet	Regulatory liabilities (current)	**1.1**	5.0	**(0.1)**	2.7
Petroleum product contracts	Balance Sheet	Regulatory assets (current)	**(0.1)**	N/A	**(0.1)**	N/A
Petroleum product contracts	Balance Sheet	Regulatory liabilities (current)	**(0.2)**	N/A	**0.2**	N/A
Petroleum product contracts	Income Statement	Operating and maintenance expense	**(0.3)**	(0.2)	**0.2**	(0.3)
Coal contract	Balance Sheet	Regulatory assets (current)	**0.3**	N/A	**(0.2)**	N/A
Coal contract	Balance Sheet	Regulatory assets (long-term)	**0.2**	N/A	**(3.0)**	N/A
Coal contract	Balance Sheet	Regulatory liabilities (long-term)		N/A	**(3.7)**	N/A

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Cash Flow Hedges

PGL uses natural gas contracts designated as cash flow hedges to hedge changes in the price of natural gas used to support operations. The cost of natural gas used to support operations is not a component of the natural gas costs recovered from customers on a one-for-one basis. These contracts extend through January 2013. PGL had the following notional volumes of outstanding contracts that were designated as cash flow hedges:

	Purchases	
	June 30, 2011	**December 31, 2010**
Natural gas (millions of therms)	**7.9**	5.4

Changes in the fair values of the effective portions of these contracts are included in OCI, net of taxes. Amounts recorded in OCI related to these cash flow hedges will be recognized in earnings when the hedged transactions occur, or if it is probable that the hedged transaction will not occur. The tables below show the amounts related to cash flow hedges recorded in OCI and in earnings.

Unrealized Loss Recognized in OCI on Derivative Instruments (Effective Portion)

	Three Months Ended June 30		**Six Months Ended June 30**	
(Millions)	**2011**	**2010**	**2011**	**2010**
Natural gas contracts	**$ (0.2)**	$	**$ (0.2)**	$ (1.1)

Loss Reclassified from Accumulated OCI into Income (Effective Portion)

		Three Months Ended June 30		**Six Months Ended June 30**	
(Millions)	**Income Statement Presentation**	**2011**	**2010**	**2011**	**2010**
Settled natural gas contracts	Operating and maintenance expense	**$ (0.2)**	$ (0.3)	**$ (0.5)**	$ (0.4)

The amount reclassified from accumulated OCI into earnings as a result of the discontinuance of cash flow hedge accounting related to these natural gas contracts was not significant during the three and six months ended June 30, 2011, and 2010. Cash flow hedge ineffectiveness related to these natural gas contracts also was not significant during the three and six months ended June 30, 2011, and 2010. When testing for effectiveness, no portion of these derivative instruments was excluded. In the next 12 months, an insignificant pre-tax loss is expected to be recognized in earnings as the hedged transactions occur.

Nonregulated Segments

Non-Hedge Derivatives

Our nonregulated segments enter into derivative contracts such as futures, forwards, options, and swaps that are not designated as accounting hedges under GAAP. In most cases, these contracts are used to manage commodity price risk associated with customer-related contracts.

The nonregulated segments had the following notional volumes of outstanding non-hedge derivative contracts:

	June 30, 2011		**December 31, 2010**	
(Millions)	**Purchases**	**Sales**	**Purchases**	**Sales**
Commodity contracts				
Natural gas (therms)	**732.2**	**790.4**	940.6	1,048.4
Electric (kilowatt-hours)	**25,304.0**	**21,974.8**	22,149.4	19,707.0
Foreign exchange contracts (Canadian dollars)	**9.5**	**9.5**	15.5	15.5

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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 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Natural gas contracts	Nonregulated revenue	**$ 6.2**	$ 5.6	**$ 14.3**	$ 8.8
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(0.1)**	(0.7)	**(0.4)**	(0.4)
Electric contracts	Nonregulated revenue	**(2.9)**	2.5	**(3.9)**	(78.2)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI) *		(1.5)	**0.2**	(1.5)
Interest rate swaps	Interest expense		0.8		0.4
Total		**$ 3.2**	$ 6.7	**$ 10.2**	$ (70.9)

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated in the current and/or prior periods.

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. The changes in the fair value of this hedge were recognized in earnings, as were the changes in fair value of the hedged item. Unrealized gains (losses) related to the fair value hedge and the related hedged item are shown in the table below.

(Millions)	Income Statement Presentation	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Interest rate swap	Interest expense	**$**	$	**$ (0.9)**	$ (0.7)
Debt hedged by swap	Interest expense			**0.9**	0.7
Total		**$**	$	**$**	$

Fair value hedge ineffectiveness recorded in interest expense on the Statements of Income was not significant for the three and six months ended June 30, 2011 and 2010. No amounts were excluded from effectiveness testing related to the interest rate swap during the three and six months ended June 30, 2011 and 2010.

Cash Flow Hedges

At June 30, 2011, Integrys Energy Services had the following notional volumes of outstanding contracts that were designated as cash flow hedges:

	June 30, 2011		December 31, 2010	
(Millions)	**Purchases**	**Sales**	**Purchases**	**Sales**
Commodity contracts				
Natural gas (therms)	**189.2**		265.6	
Electric (kilowatt-hours)	**9,924.4**	**29.8**	11,569.0	29.8

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

Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	**2011**	**2010**	**2011**	**2010**
Natural gas contracts	**$ (3.5)**	$ 0.5	**$ (2.3)**	$ (3.7)
Electric contracts	**8.4**	20.6	**3.8**	(3.3)
Interest rate swaps		(3.4)		(2.4)
Total	**$ 4.9**	$ 17.7	**$ 1.5**	$ (9.4)

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

(Millions)	Income Statement Presentation	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Settled/Realized					
Natural gas contracts	Nonregulated revenue	**$ (0.7)**	$ (1.5)	**$ (9.3)**	$ (8.8)
Electric contracts	Nonregulated revenue	**8.3**	(9.3)	**4.2**	(14.2)
Interest rate swaps	Interest expense	**(0.3)**	0.2	**(0.6)**	0.5
Hedge Designation Discontinued					
Natural gas contracts	Nonregulated revenue			**(0.3)**	0.8
Electric contracts	Nonregulated revenue		(2.0)		(9.6)
Interest rate swaps	Interest expense	**(0.2)**		**(0.2)**	
Total		**$ 7.1**	$ (12.6)	**$ (6.2)**	$ (31.3)

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	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Natural gas contracts	Nonregulated revenue	**$ (0.5)**	$ 0.1	**$ 0.3**	$ 0.1
Electric contracts	Nonregulated revenue	**(0.6)**	0.5	**(0.3)**	(0.2)
Total		**$ (1.1)**	$ 0.6	**$**	$ (0.1)

As of July 1, 2011, Integrys Energy Services discontinued the use of cash flow hedge accounting. At June 30, 2011, the amount deferred in accumulated OCI related to cash flow hedges at Integrys Energy Services was a pre-tax loss of $13.7 million. This amount relates to cash flow hedges for natural gas futures, forwards, and swaps that extend through April 2014, and electric futures, forwards, and swaps that extend through May 2017. This amount will be recognized in earnings as the forecasted transactions occur, or if it becomes probable that the forecasted transactions will not occur.

In the next 12 months, pre-tax losses of $3.4 million and $3.2 million related to the 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 substantially offset by the settlement of the related nonderivative contracts. In the next 12 months an insignificant pre-tax loss related to cash flow hedges of interest rate swaps will be amortized into earnings.

NOTE 4 RESTRUCTURING EXPENSE

Reductions in Workforce

In an effort to remove costs from our operations, we developed a plan at the end of 2009 that included reductions in our workforce. In connection with this plan, an insignificant amount of employee-related and consulting costs were included in the restructuring expense line item on the Statements of Income for the three months ended June 30, 2010 and the six months ended June 30, 2011 and 2010. No expense was recorded related to this plan during the three months ended June 30, 2011. The following table summarizes the current period activity related to these restructuring costs:

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(Millions)		Three Months Ended June 30, 2011		Six Months Ended June 30, 2011
Accrued restructuring costs at beginning of period	$		$	0.2
Add: Adjustments to accrual during the period				
Deduct: Cash payments				0.2
Accrued restructuring costs at end of period	$		$	

Integrys Energy Services Strategy Change

As part of our decision to focus Integrys Energy Services on selected retail electric and natural gas markets in the northeast quadrant of the United States and investments in energy assets with renewable attributes, the following restructuring costs were expensed:

	Three Months Ended June 30				Six Months Ended June 30			
(Millions)	2011		2010		2011		2010	
Employee-related costs	$	(0.1)	$	0.7	$	(0.1)	$	2.0
Professional fees				5.5				6.4
Accelerated lease costs and depreciation		0.9		0.3		1.9		0.5
Miscellaneous				0.2				0.3
Total restructuring expense	$	0.8	$	6.7	$	1.8	$	9.2

All of the above costs were related to the Integrys Energy Services segment and were included in the restructuring expense line item on the Statements of Income.

The following table summarizes the activity associated with employee-related restructuring expense:

(Millions)		Three Months Ended June 30, 2011		Six Months Ended June 30, 2011
Accrued employee-related costs at beginning of period	$	0.1	$	0.3
Add: Adjustments to accrual during the period		(0.1)		(0.1)
Deduct: Cash payments				0.2
Accrued employee-related costs at end of period	$		$	

We do not expect to recognize any additional restructuring costs associated with the Integrys Energy Services strategy change.

NOTE 5 DISCONTINUED OPERATIONS

Energy Management Consulting Business

During both the six months ended June 30, 2011 and 2010, Integrys Energy Services recorded a $0.1 million after-tax gain in discontinued operations when a contingent payment was earned from the sale of its energy management consulting business.

Peoples Energy Production Company

During the second quarter of 2011, we recorded a $0.9 million after-tax loss in discontinued operations when we remeasured an unrecognized tax benefits liability related to the 2007 sale of Peoples Energy Production Company. The loss represents additional state income tax expense related to the increase in our unrecognized tax benefits liability.

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NOTE 6 INVESTMENT IN ATC

Our electric transmission investment segment consists of WPS Investments LLC s ownership interest in ATC, which was approximately 34% at June 30, 2011. 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.

(Millions)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Balance at the beginning of period	**$ 422.7**	$ 404.2	**$ 416.3**	$ 395.9
Add: equity in net income	**19.9**	19.2	**39.1**	38.7
Add: capital contributions	**2.5**		**5.9**	5.1
Less: dividends received	**15.7**	16.0	**31.9**	32.3
Balance at the end of period	**$ 429.4**	$ 407.4	**$ 429.4**	$ 407.4

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

(Millions)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Income statement data				
Revenues	**$ 138.2**	$ 138.7	**$ 277.8**	$ 277.2
Operating expenses	**63.0**	62.9	**126.1**	125.7
Other expense	**19.5**	21.7	**41.8**	42.3
Net income *	**$ 55.7**	$ 54.1	**$ 109.9**	$ 109.2

* 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, 2011	December 31, 2010
Balance sheet data		
Current assets	**$ 61.4**	$ 59.9
Noncurrent assets	**2,945.5**	2,888.4
Total assets	**$ 3,006.9**	$ 2,948.3
Current liabilities	**$ 223.5**	$ 428.4
Long-term debt	**1,400.0**	1,175.0
Other noncurrent liabilities	**83.8**	84.9
Members equity	**1,299.6**	1,260.0
Total liabilities and members equity	**$ 3,006.9**	$ 2,948.3

NOTE 7 INVENTORIES

PGL and NSG price natural gas storage injections at the calendar year average of the cost of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. Due to seasonality requirements, PGL and NSG expect interim reductions in LIFO layers to be replenished by year end.

NOTE 8 GOODWILL AND OTHER INTANGIBLE ASSETS

We had no changes to the carrying amount of goodwill during the six months ended June 30, 2011, and 2010. Annual impairment tests were completed at all of Integrys Energy Group s reporting units that carried a goodwill balance in the second quarter of 2011, and no impairments resulted from these tests.

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

	June 30, 2011			December 31, 2010		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Amortized intangible assets						
Customer-related (1)	**$ 32.6**	**$ (23.3)**	**$ 9.3**	$ 32.6	$ (21.8)	$ 10.8
Natural gas and electric contract assets (2) (3)	**7.8**	**(6.3)**	**1.5**	57.1	(55.0)	2.1
Natural gas and electric contract liabilities (2)				(10.5)	10.5	
Renewable energy credits (4)	**2.8**		**2.8**	2.5		2.5
Nonregulated easements (5)	**3.8**	**(0.5)**	**3.3**	3.8	(0.4)	3.4
Emission allowances (6)	**1.7**	**(0.1)**	**1.6**	1.9	(0.2)	1.7
Other	**3.1**	**(0.5)**	**2.6**	2.4	(0.4)	2.0
Total	**$ 51.8**	**$ (30.7)**	**$ 21.1**	$ 89.8	$ (67.3)	$ 22.5
Unamortized intangible asset						
MGU trade name	**5.2**		**5.2**	5.2		5.2
Total intangible assets	**$ 57.0**	**$ (30.7)**	**$ 26.3**	$ 95.0	$ (67.3)	$ 27.7

(1) Includes customer relationship assets associated with both PELLC s former nonregulated retail natural gas and electric operations and MERC s nonutility ServiceChoice business. The remaining weighted-average amortization period for customer-related intangible assets at June 30, 2011, was approximately eight years.

(2) Represents the fair value of certain PELLC natural gas and electric customer contracts acquired in the February 2007 merger that were not considered to be derivative instruments, as well as other electric customer contracts acquired in exchange for risk management assets.

(3) Includes both short-term and long-term intangible assets related to customer contracts in the amount of $0.6 million and $0.9 million, respectively, at June 30, 2011, and $0.9 million and $1.2 million, respectively, at December 31, 2010. The remaining amortization period at June 30, 2011, was approximately three years.

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

(5) 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, 2011, of approximately 13 years.

(6) Emission allowances do not have a contractual term or expiration date. However, we are reviewing how the EPA s final CSAPR issued in July 2011 will affect our ability to use existing emission allowances in the future. See Note 12, *Commitments and Contingencies,* for more information.

Amortization related to the natural gas and electric contract intangible assets, renewable energy credits, and emission allowances is recorded as a component of nonregulated cost of fuel, natural gas, and purchased power in the Statements of Income. Amortization for the three months ended June 30, 2011, and 2010, was $0.4 million and $1.7 million, respectively. Amortization for the six months ended June 30, 2011, and 2010, was $0.7 million and $3.1 million, respectively.

Amortization related to these assets for the next five fiscal years is estimated to be:

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(Millions)		
For year ending December 31, 2011	$	3.9
For year ending December 31, 2012		0.7
For year ending December 31, 2013		0.6
For year ending December 31, 2014		0.5
For year ending December 31, 2015		0.2

Amortization expense recorded as a component of depreciation and amortization expense in the Statements of Income was $0.9 million and $1.0 million for the three months ended June 30, 2011, and 2010, respectively. Amortization expense was $1.7 million and $2.8 million for the six months ended June 30, 2011, and 2010, respectively.

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

(Millions)		
For year ending December 31, 2011	$	3.3
For year ending December 31, 2012		2.4
For year ending December 31, 2013		1.7
For year ending December 31, 2014		1.5
For year ending December 31, 2015		1.3

NOTE 9 SHORT-TERM DEBT AND LINES OF CREDIT

Our outstanding short-term borrowings consisted of sales of commercial paper and short-term notes.

(Millions, except percentages)		June 30, 2011		December 31, 2010
Commercial paper outstanding	**$**	**57.6**		
Average discount rate on outstanding commercial paper		**0.27%**		
Short-term notes payable outstanding			$	10.0
Average interest rate on short-term notes payable outstanding				0.32%

The commercial paper outstanding at June 30, 2011, had maturity dates ranging from July 1, 2011 through July 7, 2011.

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)		2011		2010
Average amount of commercial paper outstanding	**$**	**73.1**	$	104.6
Average amount of short-term notes payable outstanding		**7.3**		10.0

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We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our short-term debt, lines of credit, and remaining available capacity:

(Millions)	Maturity	June 30, 2011	December 31, 2010
Revolving credit facility (Integrys Energy Group) (1)	04/23/13	**$ 735.0**	$ 735.0
Revolving credit facility (Integrys Energy Group) (2)	06/09/11		500.0
Revolving credit facility (Integrys Energy Group) (3)	05/17/16	**200.0**	
Revolving credit facility (Integrys Energy Group) (3)	05/17/14	**275.0**	
Revolving credit facility (WPS) (1)	04/23/13	**115.0**	115.0
Revolving credit facility (WPS) (4)	05/15/12	**135.0**	
Revolving credit facility (PELLC) (2)	06/13/11		400.0
Revolving credit facility (PGL) (1)	04/23/13	**250.0**	250.0
Revolving short-term notes payable (WPS) (2)	05/13/11		10.0
Total short-term credit capacity		**$ 1,710.0**	$ 2,010.0
Less:			
Letters of credit issued inside credit facilities		**$ 39.3**	$ 64.9
Loans outstanding under credit agreements and notes payable			10.0
Commercial paper outstanding		**57.6**	
Available capacity under existing agreements		**$ 1,613.1**	$ 1,935.1

(1) Supports commercial paper borrowing program.

(2) These credit facilities and short-term note payable were terminated/repaid in May 2011.

(3) In May 2011, we entered into two new revolving credit agreements to support our commercial paper borrowing program.

(4) In May 2011, WPS entered into a new revolving credit agreement to support its commercial paper borrowing program. WPS has requested approval from the PSCW to extend this facility through May 17, 2014.

At June 30, 2011, we and each of our subsidiaries were in compliance with all respective financial covenants related to outstanding short-term debt. Our revolving credit agreements and those of certain of our subsidiaries contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%, excluding non-recourse debt. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

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NOTE 10 LONG-TERM DEBT

(Millions)	June 30, 2011	December 31, 2010
WPS (1)	**$ 872.1**	$ 872.1
UPPCO (2)	**9.4**	9.4
PELLC (3)		325.9
PGL (4)	**526.0**	526.0
NSG	**74.8**	74.8
Integrys Energy Group (5)	**774.8**	805.0
Other term loan (6)	**27.0**	27.0
Total	**2,284.1**	2,640.2
Unamortized discount	**(1.6)**	(1.7)
Total debt	**2,282.5**	2,638.5
Less current portion	**(150.9)**	(476.9)
Total long-term debt	**$ 2,131.6**	$ 2,161.6

(1) In August 2011, WPS s 6.125% Senior Notes will mature. The $150.0 million balance of these notes was included in current portion of long-term debt at June 30, 2011.

(2) On November 1, 2011, UPPCO will make a $0.9 million sinking fund payment under the terms of its First Mortgage Bonds. This payment was included in current portion of long-term debt at June 30, 2011.

(3) In January 2011, PELLC s 6.9% unsecured Senior Notes matured, and the outstanding principal balance was repaid. In January 2011, we settled the interest rate swap related to $50.0 million of the senior notes. The interest rate swap was designated as a fair value hedge. See Note 3, *Risk Management Activities*, for more information.

(4) PGL has outstanding $51.0 million of Adjustable Rate, Series OO bonds, due October 1, 2037, that are currently in a 35-day Auction Rate mode (the interest rate is reset every 35 days through an auction process). Since 2008, auctions have failed to receive sufficient clearing bids. As a result, these bonds are priced each 35 days at the maximum auction rate, until such time a successful auction occurs. The maximum auction rate is determined based on the lesser of the London Interbank Offered Rate or the Securities Industry and Financial Markets Association Municipal Swap Index rate plus a defined premium. The year-to-date weighted-average interest rate at June 30, 2011, was 0.447% for these bonds.

(5) In May 2011, we bought back $30.2 million of our $300.0 million of Junior Subordinated Notes.

(6) In April 2001, the Schuylkill County Industrial Development Authority issued $27.0 million of Refunding Tax Exempt Bonds. The proceeds from the bonds were loaned to WPS Westwood Generation, LLC, a subsidiary of Integrys Energy Services. This loan is repaid by WPS Westwood Generation to Schuylkill County Industrial Development Authority with monthly interest-only payments. The loan has a floating interest rate that is reset weekly. At June 30, 2011, the interest rate was 0.08%. The loan is to be repaid by April 2021. In January 2011, we replaced our guarantee to provide sufficient funds to pay the loan and the related obligations and indemnities on WPS Westwood Generation s obligation with a standby letter of credit. See Note 13, *Guarantees,* for more information.

At June 30, 2011, we and each of our subsidiaries were in compliance with all respective financial covenants related to outstanding long-term debt. Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. In addition, certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 11 INCOME TAXES

Our effective tax rate was 45.9% for the three months ended June 30, 2011, and 38.8% for the six months ended June 30, 2011. Our effective tax rate was 35.8% for the three months ended June 30, 2010, and 42.1% for the six months ended June 30, 2010.

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We calculate our provision for income taxes based on an interim effective tax rate that reflects our projected annual effective tax rate before certain discrete items.

Our effective tax rate for the quarter ended June 30, 2011, was higher than the federal tax rate of 35%. This difference was primarily due to tax law changes in Michigan and Wisconsin. In the second quarter of 2011, Michigan replaced its business tax with a state income tax. In accounting for this tax law change, we expensed $4.2 million of deferred income taxes related to our nonregulated operations and adjustments related to our state unitary filings. Unitary filings are required by certain states to ensure income is properly reflected in the correct tax jurisdiction. The unitary adjustments reflect additional write-offs at the holding company for deferred income tax benefits held for our consolidated tax group. Also in the second quarter of 2011, the Wisconsin tax code was conformed to the federal tax code through passage of a budget bill, retroactive to December 2010. In accounting for this tax law change, we expensed an additional $1.5 million of deferred income taxes in 2011 related to the Medicare Part D subsidy discussed below. Other state income taxes also contributed to the higher effective tax rate.

Our effective tax rate for the six months ended June 30, 2011, was higher than the federal tax rate of 35%. This difference was primarily due to state income taxes and tax law changes in Michigan and Wisconsin discussed above.

Our effective tax rate for the six months ended June 30, 2010, was higher than the federal tax rate of 35%. This difference was primarily due to state income taxes and the 2010 federal health care reform. The 2010 federal health care reform eliminated the tax deduction for retiree prescription drug charges that are paid by employers and are offset by the receipt of a federal Medicare Part D subsidy. As a result, we expensed $11.8 million of deferred income taxes during the first quarter of 2010. An increase in wind production and other tax credits partially offset the higher effective tax rate.

In the second quarter of 2011, we decreased our liability for unrecognized tax benefits by $8.9 million. For the six months ended June 30, 2011, we decreased our liability for unrecognized tax benefits by $7.9 million. The decreases were driven by the effective settlement of the following three IRS examinations in the second quarter of 2011:

- Peoples Energy Corporation and consolidated subsidiaries for the September 30, 2004 through December 31, 2006 tax years,
- Integrys Energy Group and consolidated subsidiaries for the 2006 through 2008 tax years, and
- Peoples Energy Corporation short tax year ending February 21, 2007.

In the second quarter of 2011, we also remeasured and increased our unrecognized tax benefits liability related to the sale of Peoples Energy Production Company in 2007. We expensed additional state income taxes related to this remeasurement, of which a portion was reported as discontinued operations.

NOTE 12 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, 2011.

- The electric utility segment had obligations of $176.0 million related to coal supply and transportation that extend through 2016, obligations of $1,028.2 million for either capacity or energy related to purchased power that extend through 2030, and obligations of $5.4 million for

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other commodities that extend through 2013.

- The natural gas utility segment had obligations of $1,005.0 million related to natural gas supply and transportation contracts that extend through 2028.
- Integrys Energy Services had obligations of $364.8 million, primarily related to energy and natural gas supply contracts that extend through 2020. The majority of these obligations end by 2013, with obligations of $16.9 million extending beyond 2013.
- We and our subsidiaries also had commitments of $482.5 million in the form of purchase orders issued to various vendors that relate to normal business operations, including construction projects.

Environmental

CAA New Source Review Issues

Weston and Pulliam Plants:

In November 2009, the EPA issued an 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 meet with the EPA and exchange proposals 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 an 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.

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. WP&L and the other joint owners exchanged proposals 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 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 Court stayed the proceeding until September 11, 2011, to allow the Sierra Club to participate in settlement negotiations with the EPA and the joint owners of the Columbia plant. We are currently unable to estimate the possible loss or range of loss related to this matter.

In December 2009, WPS, along with the other co-owners of the Edgewater plant, received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA. The Sierra Club cited the EPA s failure to take actions against the joint owners and operator of the Edgewater plant based upon allegations of failure to comply with the CAA. If the EPA does not take action against us and/or the other joint owners, it is likely that the Sierra Club will.

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 Court stayed the proceeding until October 4, 2011, to allow the Sierra Club to participate in settlement negotiations with the EPA and the joint owners of the Edgewater plant. We are currently unable to estimate the possible loss or range of loss related to this matter.

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EPA Settlements with Other Utilities:

In response to the EPA s CAA enforcement initiative, several utilities elected to settle with the EPA, while others are in litigation. The fines, penalties, and costs of supplemental 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.

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

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

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

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 boiler as beyond the authority of the WDNR. WPS and the WDNR continue to meet to resolve these issues. 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 Weston plant, Weston 4, Weston 1, and Weston 2, 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. Discussions with the WDNR on the severity classification of the events continue. Management believes it is likely that the WDNR will refer at least some of the NOVs to the state Justice Department for enforcement. We do not expect this matter to have a material impact on our financial statements.

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 objecting to this permit. WPS has been working with the WDNR to address the order.

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 on the issues raised by WPS, which included averaging times in the emission limits in the permit. WPS is participating in the contested case proceeding and a hearing has been set for August 31, 2011.

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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 alleges to be the EPA s unreasonable delay in performing its duties related to the grant or denial of the permit.

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. WPS is monitoring this situation with WP&L and meeting with the WDNR. 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%. 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 BACT rule. As of June 30, 2011, WPS estimates capital costs of approximately $19 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 rate cases.

In March 2011, the EPA issued a draft rule that will regulate emissions of mercury and other hazardous air pollutants. A final rule is expected in November 2011.

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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 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 CSAPR. The new rule becomes effective January 1, 2012, and as such, CAIR is still in place for the remainder of 2011. In comparison to the CAIR rule, CSAPR significantly reduces the emission allowances allocated to our existing units for sulfur dioxide and nitrogen oxide in 2012, with a further reduction in 2014.

CSAPR also establishes new sulfur dioxide and nitrogen oxide emission allowances and does 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 2011 and beyond, other than those allocated by the EPA. Sulfur dioxide emission allowances allocated under the Acid Rain Program will continue to be issued and surrendered independent of the CSAPR emission allowance program. Thus, we do not expect any material impact on our consolidated financial statements as a result of being unable to carryover 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 not indicated whether units in compliance with CSAPR will also be considered in compliance with BART.

We are currently reviewing the EPA s final rule and its potential impact on us. In order to be in compliance with CSAPR, additional sulfur dioxide and nitrogen oxide controls will need to be installed or we will have to make other changes in how we operate our existing units. The installation of these controls will be scheduled as part of WPS s long-term maintenance plan for its existing units. Due to the fact that the rule has only recently been finalized, we are currently unable to estimate the cost of compliance. However, WPS expects to recover capital costs incurred to comply with CSAPR 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 54 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, 2011, we estimated and accrued for $638.9 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, 2011, cash expenditures for environmental remediation not yet recovered in rates were $7.5 million. We recorded a regulatory asset of $646.4 million at June 30, 2011, which is net of insurance recoveries received of $59.9 million, related to the expected recovery of both cash expenditures and

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estimated future expenditures through rates.

The EPA identified NSG, the Outboard Marine Corporation, General Motors Corporation (GM), and certain other parties as potentially responsible parties (PRPs) at the Waukegan Coke Plant Site located in Waukegan, Illinois. NSG and the other PRPs are parties to a consent decree that requires NSG and GM, jointly and severally, to perform the remedial action and establish and maintain financial assurance of $21.0 million. NSG met its financial assurance requirement in the form of a net worth test, while GM met the requirement by providing a performance and payment bond in favor of the EPA. As a result of the GM bankruptcy, the EPA was granted access to the bond funds, which are expected to support a significant portion of GM s liability. The potential exposure related to the GM bankruptcy that is not expected to be covered by the bond proceeds has been reflected in the accrual identified above.

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, management believes that these costs will not have a material adverse effect on our consolidated 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 adversely affect rate recovery of such costs.

Greenhouse Gases

The EPA began regulating greenhouse gas emissions under the CAA in January 2011, by applying the BACT requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In December 2010, the EPA announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. The EPA plans to propose these standards in 2011 and finalize them in 2012. Currently there is no applicable federal or state legislation pending that specifically addresses greenhouse gas emissions.

We periodically evaluate both the technical and cost implications that may result from future state, regional, or federal greenhouse gas regulatory programs. This evaluation indicates it is probable that any regulatory program that caps emissions or imposes a carbon tax will increase costs for us and our customers. The greatest impact is likely to be on fossil fuel-fired generation, with a less significant impact on natural gas storage and distribution operations. Efforts are underway within the utility industry to find a feasible method for capturing carbon dioxide from pulverized coal-fired units and to develop cleaner ways to burn coal.

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

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NOTE 13 GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at June 30, 2011	Expiration Less Than 1 Year	Expiration 1 to 3 Years	Expiration Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	**$ 625.3**	$ 402.8	$ 4.5	$ 218.0
Standby letters of credit (2)	**69.7**	41.6	28.0	0.1
Surety bonds (3)	**10.9**	10.2	0.7	
Other guarantees (4)	**58.7**		35.0	23.7
Total guarantees	**$ 764.6**	$ 454.6	$ 68.2	$ 241.8

(1) Consists of parental guarantees of $409.2 million to support the business operations of Integrys Energy Services; $142.2 million and $61.9 million, respectively, related to natural gas supply at MERC and MGU; and $5.0 million at both PELLC and 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 $66.9 million issued to support Integrys Energy Services operations and $2.8 million related to letters of credit issued to support UPPCO, WPS, MGU, NSG, MERC, and PGL operations. These amounts are not reflected on our Balance Sheets.

(3) Primarily for workers compensation coverage and obtaining various licenses, permits, and rights of way. These guarantees are not reflected on our Balance Sheets.

(4) Consists of (a) $35.0 million 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) $8.7 million related to other indemnifications and workers compensation coverage. This amount is not reflected on our Balance Sheets.

We have provided total parental guarantees of $529.3 million on behalf of Integrys Energy Services as shown in the table below. Our exposure under these guarantees related to open transactions at June 30, 2011, was approximately $265.8 million.

(Millions)	June 30, 2011
Guarantees supporting commodity transactions	**$ 409.2**
Standby letters of credit	**66.9**
Surety bonds	**2.7**
Other	**50.5**

Total guarantees	**$**	**529.3**

NOTE 14 EMPLOYEE BENEFIT PLANS

Our defined benefit pension plans are closed to all new hires, except Local 401 union hires at MGU.

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The following table shows the components of net periodic benefit cost 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)	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Service cost	**$ 9.4**	$ 9.2	**$ 20.7**	$ 20.1	**$ 4.5**	$ 3.7	**$ 9.5**	$ 8.2
Interest cost	**19.6**	19.4	**40.1**	40.0	**7.1**	6.6	**14.8**	13.7
Expected return on plan assets	**(25.3)**	(23.8)	**(50.0)**	(46.1)	**(5.7)**	(4.8)	**(10.7)**	(9.5)
Amortization of transition obligation							**0.1**	0.1
Amortization of prior service cost (credit)	**1.3**	1.3	**2.6**	2.6	**(1.1)**	(0.9)	**(2.0)**	(1.9)
Amortization of net actuarial loss	**4.3**	1.2	**9.0**	4.1	**0.9**	0.2	**2.0**	0.9
Regulatory deferral *		1.1		2.2		(0.3)		(0.6)
Net periodic benefit cost	**$ 9.3**	$ 8.4	**$ 22.4**	$ 22.9	**$ 5.7**	$ 4.5	**$ 13.7**	$ 10.9

* The PSCW authorized WPS to recover its net increased 2009 pension costs and to refund its net decreased 2009 other postretirement benefit costs as part of the limited rate case re-opener for 2010. Amortization and recovery/refund of these costs occurred in 2010.

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 $88.8 million to our pension plans and $20.1 million to our other postretirement benefit plans during the six months ended June 30, 2011. We expect to contribute an additional $2.8 million to our pension plans and $21.1 million to our other postretirement benefit plans during the remainder of 2011. Additional contributions are dependent on various factors, including our liquidity position and the impact of tax law changes.

NOTE 15 STOCK-BASED COMPENSATION

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 values per stock option along with the assumptions incorporated into the valuation models:

	February 2011 Grant
Weighted-average fair value per option	**$6.57**

Expected term	**10 years**
Risk-free interest rate	**0.27% - 3.90%**
Expected dividend yield	**5.34%**
Expected volatility	**24.72%**

Compensation cost recognized for stock options during the three and six months ended June 30, 2011, and 2010, was not significant. As of June 30, 2011, $2.0 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of three years.

Cash received from option exercises during the six months ended June 30, 2011, was $1.7 million. The tax benefit realized from these option exercises was $0.7 million.

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A summary of stock option activity for the six months ended June 30, 2011, and information related to outstanding and exercisable stock options at June 30, 2011, 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, 2010	2,992,699	$	47.59			
Granted	**241,207**		**49.40**			
Exercised	**(184,258)**		**42.84**		**$**	**1.7**
Expired	**(13,234)**		**51.93**			
Outstanding at June 30, 2011	**3,036,414**	**$**	**48.00**	**6.15**	**$**	**14.1**
Exercisable at June 30, 2011	**2,073,904**	**$**	**49.54**	**5.14**	**$**	**7.1**

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax value that would have been received by the option holders had they all exercised their options at June 30, 2011. This is calculated as the difference between our closing stock price on June 30, 2011, and the option exercise price, multiplied by the number of in-the-money stock options.

Performance Stock Rights

Performance stock rights are accounted for as liability awards and are remeasured each reporting period during the requisite service period. The fair value of performance stock rights is estimated using a Monte Carlo valuation model, incorporating the assumptions in the table below. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. The expected volatility is estimated using three years of historical data.

	February 2011 Grant
Risk-free interest rate	**1.27%**
Expected dividend yield	**5.34%**
Expected volatility	**35.51%**

Compensation cost recognized for performance stock rights during the three months ended June 30, 2011, was $1.9 million, and was not significant for the three months ended June 30, 2010. Compensation cost recognized for performance stock rights during the six months ended June 30, 2011, and 2010, was $1.2 million and $2.5 million, respectively. As of June 30, 2011, $4.5 million of compensation cost related to unvested and outstanding performance stock rights was expected to be recognized over a weighted-average period of 2.1 years.

The tax benefit realized from the distribution of performance shares during the six months ended June 30, 2011, was $2.5 million.

A summary of the activity related to performance stock rights for the six months ended June 30, 2011, is presented below:

	Performance Stock Rights
Outstanding at December 31, 2010	341,638
Granted	**84,749**
Distributed	**(129,237)**
Adjustment for final payout	**25,013**
Outstanding at June 30, 2011	**322,163**

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The total intrinsic value of performance stock rights distributed during the 6 months ended June 30, 2011, and 2010 was $6.3 million and $1.9 million, respectively.

Restricted Shares and Restricted Share Units

Restricted shares and restricted share units are accounted for as liability awards and are remeasured each period based on our closing stock price at the reporting date.

Compensation cost recognized for restricted share and restricted share unit awards was $3.1 million during the three months ended June 30, 2011, and was not significant for the three months ended June 30, 2010. Compensation cost recognized for these awards during the six months ended June 30, 2011, and 2010 was $5.3 million and $2.8 million, respectively. As of June 30, 2011, $16.7 million of compensation cost related to unvested and outstanding restricted share and restricted share unit awards was expected to be recognized over a weighted-average period of 2.8 years.

A summary of the activity related to restricted share and restricted share unit awards for the six months ended June 30, 2011, is presented below:

	Restricted Share and Restricted Share Unit Awards
Outstanding at December 31, 2010	405,362
Granted	**170,784**
Vested	**(133,128)**
Outstanding at June 30, 2011	**443,018**

The total intrinsic value of restricted share and restricted share unit awards vested during the 6 months ended June 30, 2011, and 2010 was $6.6 million and $3.9 million, respectively.

NOTE 16 COMPREHENSIVE INCOME

Our total comprehensive income was as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(Millions)	**2011**	**2010**	**2011**	**2010**
Net income attributed to common shareholders	**$ 29.1**	$ 79.1	**$ 151.8**	$ 128.8
Cash flow hedges, net of tax (1)	**1.7**	20.1	**6.0**	7.7
Foreign currency translation, net of tax (2)		(0.7)		0.1

Amortization of unrecognized pension and other postretirement benefit costs, net of tax (2)		**0.3**				**0.5**		0.5
Total comprehensive income	**$**	**31.1**	$	98.5	**$**	**158.3**	$	137.1

(1) For the three months ended June 30, 2011 and 2010, the tax was $1.3 million and $13.0 million, respectively. For the six months ended June 30, 2011 and 2010, the tax was $4.0 million and $7.3 million, respectively.

(2) For both the three and six months ended June 30, 2011, and June 30, 2010, the tax was not significant.

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The following table shows the changes to our accumulated other comprehensive loss from December 31, 2010, to June 30, 2011.

(Millions)		
December 31, 2010 balance	$	(44.7)
Cash flow hedges, net of tax		**6.0**
Amortization of unrecognized pension and other postretirement benefit costs, net of tax		**0.5**
June 30, 2011 balance	**$**	**(38.2)**

NOTE 17 COMMON EQUITY

We had the following changes to issued common stock during the six months ended June 30, 2011:

Integrys Energy Group s common stock shares	
Common stock at December 31, 2010	77,781,685
Shares issued	
Stock Investment Plan	**233,103**
Stock-based compensation	**231,443**
Rabbi trust shares	**43,888**
Restricted stock shares retired	**(2,213)**
Common stock at June 30, 2011	**78,287,906**

From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. These stock issuances increased equity $22.2 million in 2011. Beginning May 1, 2011, we began purchasing shares on the open market to meet the requirements of these plans.

The following table reconciles common shares issued and outstanding:

	June 30, 2011			December 31, 2010		
	Shares		Average Cost	Shares		Average Cost
Common stock issued	**78,287,906**			77,781,685		
Less:						
Deferred compensation rabbi trust	**369,208**	**$**	**44.26**(1)	425,273	$	43.55(1)
Restricted stock				6,333	$	58.65(2)
Total common shares outstanding	**77,918,698**			77,350,079		

(1) 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.

(2) Based on the grant date fair value of the restricted stock.

Earnings Per Share

Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period. Diluted 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 the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, and restricted stock. The calculation of diluted earnings per share for the three months ended June 30, 2011, and 2010, excluded 0.8 million and 2.1 million, respectively, out-of-the-money stock options that had an anti-dilutive effect. The calculation of diluted earnings per share for the six months ended June 30, 2011, and 2010, excluded 0.8 million and 1.9 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:

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(Millions, except per share amounts)	Three Months Ended June 30 2011	2010	Six Months Ended June 30 2011	2010
Numerator:				
Net income from continuing operations	**$ 30.8**	$ 79.6	**$ 154.2**	$ 130.0
Discontinued operations, net of tax	**(0.9)**		**(0.8)**	0.1
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)	**(1.6)**	(1.6)
Noncontrolling interest in subsidiaries		0.3		0.3
Net income attributed to common shareholders	**$ 29.1**	$ 79.1	**$ 151.8**	$ 128.8
Denominator:				
Average shares of common stock basic	**78.7**	77.4	**78.5**	77.2
Effect of dilutive securities Stock-based compensation	**0.4**	0.5	**0.3**	0.4
Average shares of common stock diluted	**79.1**	77.9	**78.8**	77.6
Earnings per common share				
Basic	**$ 0.37**	$ 1.02	**$ 1.93**	$ 1.67
Diluted	**0.37**	1.02	**1.93**	1.66

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 are prohibited from loaning funds to us, either directly or indirectly.

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 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.

UPPCO s indentures relating to its first mortgage bonds contain certain limitations on the payment of cash dividends on its common stock.

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, 2011, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

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As of June 30, 2011, total restricted net assets were approximately $1,366.2 million. Included in this amount is our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method, which was approximately $101.2 million at June 30, 2011.

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, 2011, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Common stock dividend to parent	Return of capital to parent	Equity contributions from parent
WPS	$ 51.2	$ 75.0	$
WPS Investments, LLC (1)	31.9		6.0
PGL (2)	23.5		
NSG (2)	4.5		
TEGE	304.0	41.0	
MERC		30.0	
IBS		22.0	13.0
MGU		16.0	
UPPCO		5.5	
Total	$ 415.1	$ 189.5	$ 19.0

(1) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At June 30, 2011, WPS and UPPCO had a 12.35% and 2.63% ownership interest, respectively. Common stock dividends from WPS Investments, LLC are distributed to the owners based on their respective ownership percentages. Equity contributions to WPS Investments, LLC were made solely by us.

(2) PGL and NSG pay common stock dividends to PELLC. Subject to applicable law, PELLC does not have any dividend restrictions or limitations on distributions to us.

NOTE 18 VARIABLE INTEREST ENTITIES

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these purchased power 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 2016. The other agreement contains a tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. This contract also expires in 2016. As of June 30, 2011, and December 31, 2010, we had approximately 535 megawatts of capacity available under these agreements.

We evaluated each of these variable interest entities for possible consolidation. In these cases, 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.

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At June 30, 2011, the assets and liabilities on the Balance Sheets that related to the 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 provided or guaranteed any debt or 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 19 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, 2011			
(Millions)	Level 1	Level 2	Level 3	Total
Risk Management Assets				
Utility Segments				
FTRs	$	$	$ 5.6	$ 5.6
Natural gas contracts	1.1	2.9		4.0
Petroleum product contracts	0.7			0.7
Nonregulated Segments				
Natural gas contracts	39.1	65.9	19.3	124.3
Electric contracts	38.3	50.5	10.9	99.7
Foreign exchange contracts	0.2	1.0		1.2
Total Risk Management Assets	$ 79.4	$ 120.3	$ 35.8	$ 235.5
Risk Management Liabilities				
Utility Segments				
FTRs	$	$	$ 0.1	$ 0.1
Natural gas contracts	0.6	13.5		14.1
Coal contract			4.3	4.3
Nonregulated Segments				
Natural gas contracts	47.7	63.5	3.2	114.4
Electric contracts	42.2	75.3	20.2	137.7
Foreign exchange contracts	1.1	0.1		1.2
Total Risk Management Liabilities	$ 91.6	$ 152.4	$ 27.8	$ 271.8

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(Millions)	December 31, 2010 Level 1	Level 2	Level 3	Total
Risk Management Assets				
Utility Segments				
FTRs	$	$	$ 3.1	$ 3.1
Natural gas contracts	0.6	3.2		3.8
Petroleum product contracts	0.6			0.6
Coal contract			3.7	3.7
Nonregulated Segments				
Natural gas contracts	60.7	100.7	34.6	196.0
Electric contracts	29.5	69.8	17.4	116.7
Interest rate swaps		0.9		0.9
Foreign exchange contracts	0.1	1.4		1.5
Total Risk Management Assets	$ 91.5	$ 176.0	$ 58.8	$ 326.3
Risk Management Liabilities				
Utility Segments				
FTRs	$	$	$ 0.2	$ 0.2
Natural gas contracts	3.7	22.3		26.0
Coal contract			1.2	1.2
Nonregulated Segments				
Natural gas contracts	66.8	110.4	4.4	181.6
Electric contracts	45.0	101.5	32.3	178.8
Foreign exchange contracts	1.4	0.1		1.5
Total Risk Management Liabilities	$ 116.9	$ 234.3	$ 38.1	$ 389.3
Long-term debt hedged by fair value hedge	$	$ 50.9	$	$ 50.9

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

(Millions)	Three Months Ended June 30, 2011 Level 1	Level 2	Level 3	Three Months Ended June 30, 2010 Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$ (1.6)**	N/A	$ 0.1	$ (3.1)
Transfers into Level 2 from	**$**	**N/A**	**(4.4)**	$	N/A	(16.4)
Transfers into Level 3 from		**0.1**	**N/A**		(0.4)	N/A

Nonregulated Segments Electric Contracts

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$ (1.6)**	N/A	$ (9.8)	$ (17.4)
Transfers into Level 2 from	**$**	**N/A**	**(6.8)**	$	N/A	6.8
Transfers into Level 3 from		**(5.3)**	**N/A**		(4.8)	N/A

<u>Nonregulated Segments Natural Gas Contracts</u>

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**0.2**	$	N/A	
Transfers into Level 3 from		**0.1**	**N/A**			N/A

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Nonregulated Segments Natural Gas Contracts

	Six Months Ended June 30, 2011			Six Months Ended June 30, 2010		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**0.6**	$	N/A	
Transfers into Level 3 from			**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.

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, 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**

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 losses 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**

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Three Months Ended June 30, 2010

(Millions)	Nonregulated Segments Natural Gas	Nonregulated Segments Electric	Utility Segments FTRs	Total
Balance at the beginning of the period	$ 36.8	$ (132.3)	$ 1.5	$ (94.0)
Net realized and unrealized gains included in earnings	5.2	35.9	3.7	44.8
Net unrealized gains recorded as regulatory assets or liabilities			3.5	3.5
Net unrealized gains included in other comprehensive loss		10.0		10.0
Net purchases and settlements	(9.0)	31.2	(1.1)	21.1
Net transfers into Level 3		(0.4)		(0.4)
Net transfers out of Level 3		19.5		19.5
Balance at the end of the period	$ 33.0	$ (36.1)	$ 7.6	$ 4.5
Net unrealized gains included in earnings related to instruments still held at the end of the period	$ 5.2	$ 35.9	$	$ 41.1

Six Months Ended June 30, 2010

(Millions)	Nonregulated Segments Natural Gas	Nonregulated Segments Electric	Utility Segments FTRs	Total
Balance at the beginning of the period	$ 31.4	$ 86.5	$ 3.5	$ 121.4
Net realized and unrealized gains (losses) included in earnings	22.4	(58.9)	3.5	(33.0)
Net unrealized gains recorded as regulatory assets or liabilities			2.1	2.1
Net unrealized losses included in other comprehensive loss		(3.2)		(3.2)
Net purchases and settlements	(20.8)	(66.3)	(1.5)	(88.6)
Net transfers into Level 3		(4.8)		(4.8)
Net transfers out of Level 3		10.6		10.6
Balance at the end of the period	$ 33.0	$ (36.1)	$ 7.6	$ 4.5
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 22.4	$ (58.9)	$	$ (36.5)

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 fuel, natural gas, and purchased power, 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, 2011		December 31, 2010	
(Millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	**$ 2,282.5**	**$ 2,396.0**	$ 2,638.5	$ 2,687.8
Preferred stock	**51.1**	**49.7**	51.1	46.8

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.

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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 20 MISCELLANEOUS INCOME

Total miscellaneous income was as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	**2011**	**2010**	**2011**	**2010**
Equity earnings on investments	**$ 20.3**	$ 19.8	**$ 39.7**	$ 39.5
Key executive life insurance	**1.0**	2.0	**1.1**	2.0
Interest and dividend income	**0.5**	1.1	**0.5**	2.1
Other	**(0.2)**	1.5	**1.5**	1.2
Total miscellaneous income	**$ 21.6**	$ 24.4	**$ 42.8**	$ 44.8

NOTE 21 REGULATORY ENVIRONMENT

Wisconsin

2012 Rate Reopener

On May 2, 2011, WPS filed a rate reopener with the PSCW for limited items. WPS requested an electric rate increase of $33.7 million and a natural gas rate increase of $1.1 million, to be effective January 1, 2012. WPS subsequently agreed to withdraw its request for a natural gas rate increase. The proposed electric rate increase is primarily driven by higher fuel and purchased power costs, higher transmission costs, and increased Focus on Energy payments in 2012. In response to the final EPA CSAPR issued in July 2011, WPS is reviewing the fuel cost amounts submitted in this filing, as they are expected to increase as a result of this new rule. We do not expect this to delay the PSCW s final ruling on this matter.

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. However, the rate order assumed declining sales volumes, a lower authorized return on common equity, lower rate base, and other reduced costs, which results in lower total revenues and margins. The $21.0 million included $20.0 million of recovery of prior deferrals, the majority of which relates 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, resulting in lower natural gas revenues and margins. The new rates reflect 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 is 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. As of June 30, 2011, a $4.1 million refund for fuel and purchased power over-collections was deferred as a short-term regulatory liability.

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2010 Rates

On December 22, 2009, the PSCW issued a final written order for WPS, effective January 1, 2010. It authorized an electric rate increase of $18.2 million, offset by an $18.2 million refund of 2009 and 2008 fuel cost over-collections. It also authorized a retail natural gas rate increase of $13.5 million. Based on an order issued on April 1, 2010, the remaining $10.0 million of the total 2008 and 2009 fuel cost over-collections, plus interest of $1.3 million, was refunded to customers in April and May 2010. The 2010 fuel cost over-collections were made subject to refund as of that date. As of June 30, 2011, the balance of the 2010 fuel cost over-collections to be refunded to customers throughout 2011 was $7.7 million, which was recorded as a short-term regulatory liability.

Michigan

2012 UPPCO Rate Case

On June 30, 2011, UPPCO filed an application with the MPSC to increase retail electric rates $7.7 million, with rates effective January 1, 2012. The filing requests a 10.75% return on common equity and a common equity ratio of 54.90% in UPPCO s regulatory capital structure. The proposed rate increase is primarily driven by increased capital investments associated with FERC-required replacements and upgrades of hydroelectric facilities, reduced wholesale sales, and increased employee benefit costs.

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 reflect a 10.30% return on common equity and a common equity ratio of 54.86% in UPPCO s regulatory capital structure. The order requires that UPPCO terminate its uncollectibles expense tracking mechanism (discussed below) after the close of December 2010 business, but retains the decoupling mechanism.

2010 UPPCO Rates

On December 16, 2009, the MPSC issued a final written order for UPPCO authorizing a retail electric rate increase of $6.5 million, effective January 1, 2010. The new rates reflected a 10.90% return on common equity and a common equity ratio of 54.83% in UPPCO s regulatory capital structure. The order included approval of a decoupling mechanism, as well as an uncollectibles expense tracking mechanism, both effective January 1, 2010. The uncollectibles expense tracking mechanism allows for the deferral and subsequent recovery or refund of 80% of the difference between actual write-offs (net of recoveries) and bad debt expense included in utility rates.

2010 MGU Rates

On December 16, 2009, the MPSC issued a final written order for MGU authorizing a retail natural gas rate increase of $3.5 million, effective January 1, 2010. The new rates reflect a 10.75% return on common equity and a common equity ratio of 50.26% in MGU s regulatory capital structure. The order included approval of an uncollectibles expense tracking mechanism, effective January 1, 2010. This mechanism allows for the deferral and subsequent recovery or refund of 80% of the difference between actual write-offs (net of recoveries) and bad debt expense included in utility rates. The MPSC also granted a decoupling mechanism for MGU, which adjusts for the impact on revenues of changes in weather-normalized use per customer for residential and small commercial customers, effective January 1, 2010.

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Illinois

2011 Rate Cases

On February 15, 2011, PGL and NSG filed applications with the ICC to increase retail natural gas rates $125.4 million and $8.7 million, respectively, with rates expected to be effective in January 2012. The filings for both PGL and NSG include requests for an 11.25% return on common equity and a common equity ratio of 56.00% in their regulatory capital structures. PGL and NSG each requested that the ICC make their decoupling mechanisms permanent.

On June 15, 2011, the ICC Staff and interveners filed direct testimony in these cases. The ICC Staff recommended a rate increase of $47.7 million for PGL and a rate decrease of $0.3 million for NSG. The ICC Staff recommendations were based, in part, on an 8.75% return on common equity for both PGL and NSG and a common equity ratio of 48.40% in each of their regulatory capital structures. The ICC Staff supported making the decoupling mechanisms permanent. The interveners testimony included a return on common equity range of 7.22% to 9.16%. For PGL, the interveners proposed rate increase ranged from $14.9 million to $37.2 million. For NSG, the interveners proposal ranged from a rate decrease of $0.8 million to a rate increase of $2.4 million. The interveners opposed making the decoupling mechanisms permanent.

PGL and NSG filed rebuttal testimony on July 13, 2011, and reduced their requested return on common equity to 10.85%. PGL reduced its requested rate increase to $113.3 million. NSG reduced its requested rate increase to $8.5 million.

2010 Rates

On January 21, 2010, the ICC issued a final order authorizing a retail natural gas rate increase of $69.8 million for PGL and $13.9 million for NSG, effective January 28, 2010. The rates for PGL reflect a 10.23% return on common equity and a common equity ratio of 56.00% in PGL s regulatory capital structure. The rates for NSG reflect a 10.33% return on common equity and a common equity ratio of 56.00% in NSG s regulatory capital structure. The rate order approved the recovery of net dismantling costs of property, plant, and equipment over the life of the asset rather than when incurred. PGL and NSG filed appeals related to the rate order with the Illinois Appellate Court, First District.

The ICC also approved a rider mechanism for PGL to 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. The Illinois Attorney General and the Citizens Utility Board filed appeals related to Rider ICR with the Illinois Appellate Court, First District.

Single issue ratemaking is one of the arguments raised in the pending appeal of Rider ICR, and in the pending appeal before the Illinois Appellate Court, Second District, of NSG s and PGL s decoupling mechanism approved in the 2008 rate case. On September 30, 2010, the Illinois Appellate Court, Second District, issued a decision which, among other things, rejected the ICC s approval of a Commonwealth Edison Company (ComEd) cost recovery mechanism for advanced metering technology (also called smart grid) because it was improper single issue ratemaking. Integrys Energy Group is evaluating the decision of the Illinois Appellate Court, Second District, in light of other, contrary precedents to determine whether differences in the decoupling mechanism and Rider ICR distinguish them from ComEd s rider.

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2009 Illinois Legislation

In July 2009, Illinois Senate Bill (SB) 1918 was signed into law. Under SB 1918, PGL and NSG filed a bad debt rider with the ICC in September 2009 to recover (or refund) the incremental difference between the rate case authorized uncollectible expense and the actual uncollectible expense reported to the ICC each year. The ICC approved the rider in February 2010. SB 1918 also requires a percentage of income payment plan for low-income utility customers, which PGL and NSG began offering as a transition program in 2010, with a permanent program scheduled to begin August 28, 2011. Additionally, SB 1918 requires an on-bill financing program that PGL and NSG will operate with their EEP. It will allow certain residential customers to borrow funds from a third-party lender to invest in energy saving measures and to pay the funds back over time through a charge on their utility bill. Finally, SB 1918 requires an EEP to meet specified energy efficiency standards, which the ICC approved in May 2011. The first program year began June 2011.

Minnesota

2011 Rates

On November 30, 2010, MERC filed an application with the MPUC to increase retail natural gas rates by $15.2 million. Interim rates were effective February 2011 and final rates are expected to be effective during the first quarter of 2012. The filing includes a request for an 11.25% return on common equity and a common equity ratio of 50.20% in MERC s regulatory capital structure. On January 28, 2011, the MPUC approved an interim rate order authorizing MERC a retail natural gas rate increase of $7.5 million, effective February 1, 2011. The interim rates reflect a 10.21% return on common equity and a common equity ratio of 50.20% in MERC s regulatory capital structure.

2010 Rates

On December 4, 2009, the MPUC approved a final written order for MERC authorizing a retail natural gas rate increase of $15.4 million, effective January 1, 2010. The new rates reflected a 10.21% return on common equity and a common equity ratio of 48.77% in MERC s regulatory capital structure. Since the final approved rate increase was lower than the interim rate increase that went into effect in October 2008, refunds of $5.5 million were made to customers in March 2010. MERC also received MPUC approval in 2010 to increase its per therm cost recovery charges related to its conservation improvement program.

Federal

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

Integrys Energy Services initially expensed all but $4.5 million of the total $19.2 million of billings received for the 16-month transitional period, as it was considered probable that at least $4.5 million of the billings would be recovered due to inconsistencies between the FERC s SECA order and the transmission owners compliance filings. Subsequent to receiving the billings, Integrys Energy Services reached settlement agreements with vendors for a combined $1.6 million, reducing the $4.5 million receivable balance to approximately $3 million.

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 issued an order on the Initial Decision. In that order, the FERC ruled favorably for Integrys Energy Services on two issues, which are expected to result in additional refunds of approximately $2 million, but reversed the

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rulings of the Initial Decision on nearly every other substantive issue. As a result of this ruling, Integrys Energy Services expensed, as a component of margin, approximately $1 million in the second quarter of 2010. Integrys Energy Services and numerous other parties filed for rehearing of the FERC s order. Any refunds to Integrys Energy Services will include interest for the period from payment to refund.

NOTE 22 SEGMENTS OF BUSINESS

During the fourth quarter of 2010, we changed our method of accounting for ITCs from the flow-through method to the deferral method. As such, certain previously reported amounts were retrospectively adjusted. See Note 1, *Financial Information*, for more information.

At June 30, 2011, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of WPS, MGU, MERC, PGL, and NSG.
- The electric utility segment includes the regulated electric utility operations of WPS and UPPCO.
- 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 WPS, MGU, MERC, UPPCO, PGL, NSG, and IBS. Equity earnings from our investment in WRPC are also included in the holding company and other segment.

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, 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**
Miscellaneous income	**1.3**	**0.2**	**19.9**	**21.4**	**0.4**	**6.0**	**(6.2)**	**21.6**
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**

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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, 2010								
External revenues	$ 296.8	$ 314.0	$	$ 610.8	$ 401.0	$ 3.0	$	$ 1,014.8
Intersegment revenues	0.1	6.9		7.0	0.2		(7.2)	
Restructuring expense	(0.1)	(0.1)		(0.2)	6.7			6.5
Net gain on Integrys Energy Services dispositions related to strategy change					(25.0)			(25.0)
Depreciation and amortization expense	32.6	24.6		57.2	4.4	6.2		67.8
Miscellaneous income	0.3	0.3	19.2	19.8	2.4	12.8	(10.6)	24.4
Interest expense	12.8	10.7		23.5	1.4	22.3	(10.6)	36.6
Provision (benefit) for income taxes	(1.2)	13.8	7.7	20.3	27.7	(3.6)		44.4
Preferred stock dividends of subsidiary	(0.1)	(0.7)		(0.8)				(0.8)
Noncontrolling interest in subsidiaries					0.3			0.3
Net income (loss) attributed to common shareholders	(1.7)	26.2	11.5	36.0	45.8	(2.7)		79.1

(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, 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**
Miscellaneous income	**1.4**	**0.5**	**39.1**	**41.0**	**1.3**	**12.2**	**(11.7)**	**42.8**
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**

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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, 2010								
External revenues	$ 1,223.3	$ 644.1	$	$ 1,867.4	$ 1,044.8	$ 6.0	$	$ 2,918.2
Intersegment revenues	0.3	11.7		12.0	1.0		(13.0)	
Restructuring expense	(0.1)	(0.1)		(0.2)	9.2	0.2		9.2
Net loss on Integrys Energy Services dispositions related to strategy change					14.8			14.8
Depreciation and amortization expense	63.3	49.0		112.3	9.0	10.6		131.9
Miscellaneous income	0.8	0.5	38.7	40.0	2.9	23.3	(21.4)	44.8
Interest expense	25.9	21.5		47.4	4.8	45.2	(21.4)	76.0
Provision (benefit) for income taxes	55.4	31.9	15.6	102.9	(1.3)	(7.2)		94.4
Net income (loss) from continuing operations	68.3	53.6	23.1	145.0	(2.9)	(12.1)		130.0
Discontinued operations					0.1			0.1
Preferred stock dividends of subsidiary	(0.3)	(1.3)		(1.6)				(1.6)
Noncontrolling interest in subsidiaries					0.3			0.3
Net income (loss) attributed to common shareholders	68.0	52.3	23.1	143.4	(2.5)	(12.1)		128.8

NOTE 23 NEW ACCOUNTING PRONOUNCEMENTS

ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS), was issued in May 2011. The amendments change the wording used to describe the requirements for measuring fair value and for disclosing information about fair value measurements. The amendments also clarify the intent concerning the application of existing fair value measurement requirements. This guidance is effective for our reporting period ending March 31, 2012. Management is currently evaluating the impact that the adoption will have on our financial statements.

ASU 2011-05, Presentation of Comprehensive Income, was issued in June 2011. The guidance requires that the total of comprehensive income, the components of net income, and the components of other comprehensive income be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Reclassification adjustments from other comprehensive income to net income are also required to be reported on the face of the financial statements. This guidance is effective for our reporting period ending March 31, 2012. Management is currently evaluating the impact that the adoption will have 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, 2010.

SUMMARY

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

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Change in 2011 Over 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010	Change in 2011 Over 2010
Natural gas utility operations	**$ 1.2**	$ (1.7)	N/A	**$ 78.4**	$ 68.0	15.3%
Electric utility operations	**18.2**	26.2	(30.5)%	**43.3**	52.3	(17.2)%
Electric transmission investment	**12.0**	11.5	4.3%	**23.4**	23.1	1.3%
Integrys Energy Services operations	**6.0**	45.8	(86.9)%	**16.8**	(2.5)	N/A
Holding company and other operations	**(8.3)**	(2.7)	207.4%	**(10.1)**	(12.1)	(16.5)%
Net income attributed to common shareholders	**$ 29.1**	$ 79.1	(63.2)%	**$ 151.8**	$ 128.8	17.9%
Basic earnings per share	**$ 0.37**	$ 1.02	(63.7)%	**$ 1.93**	$ 1.67	15.6%
Diluted earnings per share	**$ 0.37**	$ 1.02	(63.7)%	**$ 1.93**	$ 1.66	16.3%
Average shares of common stock						
Basic	**78.7**	77.4	1.7%	**78.5**	77.2	1.7%
Diluted	**79.1**	77.9	1.5%	**78.8**	77.6	1.5%

Second Quarter 2011 Compared with Second Quarter 2010

Our 2011 second quarter earnings were $29.1 million, compared with 2010 second quarter earnings of $79.1 million. The $50.0 million decrease in earnings was driven by:

- A $27.7 million after-tax non-cash decrease in nonregulated margins related to derivative fair value adjustments.
- A $14.9 million after-tax decrease in gains on dispositions related to the Integrys Energy Services strategy change.
- A $7.5 million after-tax increase in operating expense at the utilities, driven by higher natural gas distribution costs due to certain costs related to the work asset management system and AMRP projects. This increase was also due to higher maintenance expense at WPS driven by the timing of scheduled plant outages.
- A $4.2 million after-tax decrease due to a change in tax law in Michigan.

These decreases were partially offset by a $4.5 million after-tax increase in natural gas utility margins, mainly due to increased sales volumes.

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Six Months 2011 Compared with Six Months 2010

Our earnings for the first six months of 2011 were $151.8 million, compared with $128.8 million for the same period in 2010. The primary drivers of the $23.0 million increase in earnings were:

- The $11.8 million positive period-over-period impact of deferred income tax benefits expensed in the first quarter of 2010 related to federal health care legislation.
- A $9.0 million after-tax decrease in net losses on dispositions related to the Integrys Energy Services strategy change.
- A $6.3 million after-tax increase in natural gas utility margins, mainly due to higher sales volumes.
- A $4.4 million after-tax decrease in restructuring expense.

These increases were partially offset by a $7.3 million after-tax decrease in electric utility margins, mainly caused by differences at WPS in the current rate order compared with the previous rate order.

Regulated Natural Gas Utility Segment Operations

(Millions, except heating degree days)	Three Months Ended June 30 2011	2010	Change in 2011 Over 2010	Six Months Ended June 30 2011	2010	Change in 2011 Over 2010
Revenues	**$ 364.0**	$ 296.9	22.6%	**$ 1,217.4**	$ 1,223.6	(0.5)%
Purchased natural gas costs	**180.6**	121.0	49.3%	**711.7**	728.4	(2.3)%
Margins	**183.4**	175.9	4.3%	**505.7**	495.2	2.1%
Operating and maintenance expense	**130.8**	125.6	4.1%	**270.6**	266.1	1.7%
Depreciation and amortization expense	**31.3**	32.6	(4.0)%	**62.5**	63.3	(1.3)%
Taxes other than income taxes	**8.2**	8.0	2.5%	**17.6**	17.0	3.5%
Operating income	**13.1**	9.7	35.1%	**155.0**	148.8	4.2%
Miscellaneous income	**1.3**	0.3	333.3%	**1.4**	0.8	75.0%
Interest expense	**(12.2)**	(12.8)	(4.7)%	**(24.6)**	(25.9)	(5.0)%
Other expense	**(10.9)**	(12.5)	(12.8)%	**(23.2)**	(25.1)	(7.6)%
Income (loss) before taxes	**$ 2.2**	$ (2.8)	N/A	**$ 131.8**	$ 123.7	6.5%
Retail throughput in therms						
Residential	**228.6**	162.9	40.3%	**1,011.0**	899.4	12.4%
Commercial and industrial	**67.0**	48.7	37.6%	**305.4**	273.2	11.8%
Other	**12.2**	7.6	60.5%	**33.7**	27.0	24.8%
Total retail throughput in therms	**307.8**	219.2	40.4%	**1,350.1**	1,199.6	12.5%
Transport throughput in therms						

Residential	**39.5**	29.5	33.9%	**154.0**	134.3	14.7%
Commercial and industrial	**331.3**	282.4	17.3%	**868.0**	779.0	11.4%
Total transport throughput in therms	**370.8**	311.9	18.9%	**1,022.0**	913.3	11.9%
Total throughput in therms	**678.6**	531.1	27.8%	**2,372.1**	2,112.9	12.3%
Weather						
Average heating degree days	**890**	580	53.4%	**4,452**	3,862	15.3%

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Second Quarter 2011 Compared with Second Quarter 2010

Revenues

Regulated natural gas utility segment revenues increased $67.1 million, driven by:

- An approximate $60 million net increase in revenues as a result of the 27.8% increase in volumes sold.
  - Colder weather during the 2011 heating season, as shown by the 53.4% increase in heating degree days, drove an approximate $50 million increase in revenues.
  - Higher sales volumes excluding the impact of weather resulted in approximately $20 million of additional revenues. We attribute this increase to a combination of higher use per customer, higher average customer counts and improved economic conditions for certain customer classes in certain service territories.
  - Partially offsetting these increases was an approximate $10 million decrease from decoupling mechanisms. Although decoupling was implemented to minimize the impact of changes in sales volumes, we do not have approval to use decoupling in all jurisdictions. In addition, decoupling only covers residential and small commercial and industrial customers and does not adjust for changes in customer counts. Finally, at MGU, weather impacts are excluded from decoupling. During the 2011 heating season, our natural gas utilities had higher sales volumes from significantly colder than normal weather. However, decoupling lessened the positive impact from the increased sales volumes through higher future customer refunds.
- An approximate $11 million increase in revenues as a result of an approximate 10% increase in the average per-unit cost of natural gas sold. We pass through prudently incurred natural gas commodity costs to our customers in current rates.
- A partially offsetting approximate $4 million decrease in revenues caused by increased refunds to customers under the PGL and NSG bad debt riders. We amortized regulatory liabilities set up under the bad debt rider as the related amounts were refunded to customers. Therefore, the refunds did not impact earnings, as they were offset by a decrease in operating and maintenance expense. See Note 21, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders.
- A partially offsetting approximate $1 million net decrease in revenues from rate orders. See Note 21, *Regulatory Environment,* for more information on these rate orders.
  - The rate decrease at WPS, effective January 14, 2011, had an approximate $4 million negative impact on revenues.
  - There was a $3 million positive impact from rate orders at MERC. The conservation improvement program (CIP) rate increase, effective November 2010, and the interim rate increase, effective February 1, 2011, both increased revenues. The CIP revenues did not impact earnings as they were offset by an increase in operating and maintenance expense.

Margins

Regulated natural gas utility segment margins increased $7.5 million. An increase in sales volumes, net of decoupling, drove an approximate $11 million increase. This increase was partially offset by approximately $4 million of refunds to customers related to the PGL and NSG bad debt riders. Amortization of the related regulatory liabilities offset the decrease in margins, resulting in no impact on earnings. The approximate $1 million net negative impact of the rate orders discussed above also partially offset the increase in margins.

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Operating Income

Operating income at the regulated natural gas utility segment increased $3.4 million. This increase was primarily driven by the $7.5 million increase in margins discussed above, partially offset by a $5.2 million increase in operating and maintenance expenses.

The increase in operating and maintenance expenses primarily related to:

- A $5.3 million increase in natural gas distribution costs. The increase was partially due to additional labor and consulting expenses associated with a work asset management system and the AMRP. Transportation and other miscellaneous gas distribution costs also contributed to the increase.
- A $2.8 million increase in expenses for energy conservation and efficiency programs. Expenses related to the CIP were recovered through a rate increase discussed above, resulting in no impact on earnings for the CIP portion of the increase.
- A $1.7 million increase in pension expense, primarily at PGL. This increase was driven by lower expected returns on plan assets caused by a lower assumed rate of return in 2011 and a decline in the market value of the plan assets. The decline in market value was driven both by negative pension investment returns in 2008 and benefit payments to plan participants.
- These increases were partially offset by:
  - An approximate $4 million decrease due to higher amortization of regulatory liabilities related to the PGL and NSG bad debt riders. Revenues decreased by an equal amount, resulting in no impact on earnings.
  - A $1.9 million net decrease in certain legal accruals and injuries and damages expenses.

Six Months 2011 Compared with Six Months 2010

Revenues

Regulated natural gas utility segment revenues decreased $6.2 million, driven by:

- An approximate $99 million decrease in revenues as a result of an approximate 13% decrease in the average per-unit cost of natural gas sold. We pass through prudently incurred natural gas commodity costs to our customers in current rates.
- An approximate $8 million decrease in revenues related to lower recovery of certain net regulatory assets. We refunded approximately $5 million more to customers under the PGL and NSG bad debt riders. We also recovered approximately $3 million less for environmental cleanup costs of former manufactured gas plant sites. These lower recoveries did not impact earnings, as they were offset by a decrease in operating and maintenance expense. See Note 21, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders.

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- A partially offsetting approximate $92 million net increase in revenues as a result of a 12.3% increase in volumes sold.
  - Colder weather during the 2011 heating season, as shown by the 15.3% increase in heating degree days, drove an approximate $94 million increase in revenues.
  - Higher sales volumes excluding the impact of weather resulted in approximately $24 million of additional revenues. We attribute this increase to a combination of higher use per customer, higher average customer counts and improved economic conditions for certain customer classes in certain service territories.
  - Partially offsetting these increases was the approximate $26 million decrease from decoupling mechanisms at certain natural gas utilities. Although decoupling was implemented to minimize the impact of changes in sales volumes, we do not have approval to use decoupling in all jurisdictions. In addition, decoupling only covers residential and small commercial and industrial customers and does not adjust for changes in customer counts. Finally, at MGU, weather impacts are excluded from decoupling. During the 2011 heating season, our natural gas utilities had higher sales volumes from significantly colder than normal weather. However, decoupling minimized the positive impact from the increased sales volumes through higher future customer refunds.
- A partially offsetting approximate $6 million net increase in revenues from rate orders. Rate orders were necessary, in part, to recover higher operating expenses (as discussed below). See Note 21, *Regulatory Environment,* for more information on these rate orders.
  - MERC s CIP rate increase, effective November 2010, and its interim natural gas distribution rate increase, effective February 1, 2011, had an approximate $8 million positive impact on revenues. The CIP revenues did not impact earnings as they were offset by an increase in operating and maintenance expense.
  - The rate increases at PGL and NSG that went into effect January 28, 2010, and other impacts of rate design, had an approximate $7 million net positive impact on revenues.
  - The approximate $9 million rate decrease at WPS, effective January 14, 2011, partially offset these increases.

Margins

Regulated natural gas utility segment margins increased $10.5 million. An increase in sales volumes, net of decoupling, drove an approximate $9 million increase in margins. The approximate $6 million net positive impact of the rate orders discussed above also increased margins. These increases were partially offset by an approximate $8 million decrease due to lower recovery of net regulatory assets. Amortization of the related net regulatory assets offset the decrease in margins, resulting in no impact on earnings.

Operating Income

Operating income at the regulated natural gas utility segment increased $6.2 million. This increase was primarily driven by the $10.5 million increase in margins discussed above. A $4.5 million increase in operating and maintenance expenses partially offset the increase.

The increase in operating and maintenance expenses primarily related to:

- An $8.2 million increase in natural gas distribution costs. The increase was partially due to additional labor and consulting expenses associated with a work asset management system and the AMRP. Transportation and other miscellaneous natural gas distribution costs also contributed to the increase.

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- A $6.6 million increase in expenses related to energy conservation and efficiency programs. Expenses related to the CIP were recovered through a rate increase discussed above, resulting in no impact on earnings for the CIP portion of this increase.

- A $3.0 million increase in pension expense, primarily at PGL. This increase was driven by lower expected returns on plan assets caused by a lower assumed rate of return in 2011 and a decline in the market value of the plan assets. The decline in market value was driven both by negative pension investment returns in 2008 and benefit payments to plan participants.

- These increases were partially offset by:

  - An approximate $8 million decrease due to lower amortization of net regulatory assets related to the PGL and NSG bad debt riders and environmental cleanup costs for manufactured gas plant sites. Revenues decreased by an equal amount, resulting in no impact on earnings.

  - A $1.9 million net decrease in certain legal accruals and injuries and damages expenses.

  - A $1.0 million decrease in bad debt expense driven primarily by the bad debt rider at PGL. For 2011, PGL recorded bad debt expense based on amounts approved in its most recent rate order, which was effective January 28, 2010. Bad debt expense was recorded prior to January 28, 2010, based on a higher amount approved in PGL s previous rate order.

  - A $1.0 million decrease in labor costs as a result of the reduction in workforce implemented as part of previously announced cost management efforts.

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Regulated Electric Utility Segment Operations

(Millions, except heating degree days)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Change in 2011 Over 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010	Change in 2011 Over 2010
Revenues	**$ 315.4**	$ 320.9	(1.7)%	**$ 638.0**	$ 655.8	(2.7)%
Fuel and purchased power costs	**133.6**	136.6	(2.2)%	**271.4**	277.0	(2.0)%
Margins	**181.8**	184.3	(1.4)%	**366.6**	378.8	(3.2)%
Operating and maintenance expense	**106.5**	97.8	8.9%	**207.7**	200.3	3.7%
Depreciation and amortization expense	**22.0**	24.6	(10.6)%	**44.1**	49.0	(10.0)%
Taxes other than income taxes	**12.0**	10.8	11.1%	**24.3**	23.0	5.7%
Operating income	**41.3**	51.1	(19.2)%	**90.5**	106.5	(15.0)%
Miscellaneous income	**0.2**	0.3	(33.3)%	**0.5**	0.5	%
Interest expense	**(11.8)**	(10.7)	10.3%	**(23.8)**	(21.5)	10.7%
Other expense	**(11.6)**	(10.4)	11.5%	**(23.3)**	(21.0)	11.0%
Income before taxes	**$ 29.7**	$ 40.7	(27.0)%	**$ 67.2**	$ 85.5	(21.4)%
Sales in kilowatt-hours						
Residential	**685.2**	684.1	0.2%	**1,499.5**	1,476.9	1.5%
Commercial and industrial	**2,093.4**	2,119.0	(1.2)%	**4,146.6**	4,146.0	%
Wholesale	**1,136.0**	1,248.1	(9.0)%	**2,198.2**	2,459.8	(10.6)%
Other	**7.8**	8.0	(2.5)%	**18.8**	19.2	(2.1)%
Total sales in kilowatt-hours	**3,922.4**	4,059.2	(3.4)%	**7,863.1**	8,101.9	(2.9)%
Weather						
WPS:						
Heating degree days	**1,084**	744	45.7%	**4,976**	4,188	18.8%
Cooling degree days	**102**	138	(26.1)%	**102**	138	(26.1)%
UPPCO:						
Heating degree days	**1,487**	1,110	34.0%	**5,595**	4,702	19.0%
Cooling degree days	**31**	57	(45.6)%	**31**	57	(45.6)%

Second Quarter 2011 Compared with Second Quarter 2010

Revenues

Regulated electric utility segment revenues decreased $5.5 million, driven by:

- An approximate $7 million decrease in revenues from wholesale customers. The decrease is primarily due to the closing of a customer s plant and lower non-fuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.

- An approximate $3 million decrease in revenues due to an approximate 1% decrease in sales volumes to retail customers.
- These decreases were partially offset by:
  - An approximate $4 million increase in revenues due to differences between the current WPS rate order and the previous rate order as calculated on a per unit basis. The decoupling mechanism did not have a significant impact on the quarter-over-quarter change. For more details on the current rate order, see Note 21, *Regulatory Environment*.

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- An approximate $1 million increase in revenues driven by a retail electric rate increase at UPPCO.

Margins

Regulated electric utility segment margins decreased $2.5 million, driven by:

- An approximate $2 million decrease in margins from wholesale customers. The decrease is primarily due to lower non-fuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.
- An approximate $2 million decrease in margins due to an approximate 1% decrease in sales volumes to retail customers.
- These decreases were partially offset by:
  - An approximate $1 million increase in margins due to differences between the current WPS rate order and the previous rate order as calculated on a per unit basis. The decoupling mechanism did not have a significant impact on the quarter-over-quarter change. For more details on the current rate order, see Note 21, *Regulatory Environment*.
  - An approximate $1 million increase in margins driven by a retail electric rate increase at UPPCO.

Operating Income

Operating income at the regulated electric utility segment decreased $9.8 million, driven by the $2.5 million decrease in margins and a $7.3 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $3.4 million increase in maintenance expense. One of the main drivers of this increase was the timing of scheduled plant outages.
- A $1.5 million increase in the amortization of various regulatory deferrals. This increase was offset in revenues, resulting in no impact on earnings.
- A $1.2 million increase in taxes other than income taxes due to increases in property taxes, payroll taxes, and gross receipts tax.
- A $1.0 million increase in customer assistance expense related to payments made to the Focus on Energy program. The program helps residents and businesses install cost-effective, energy efficient, and renewable energy products.
- A $2.8 million increase in various operating expenses, none of which were individually significant.
- A partially offsetting $2.6 million decrease in depreciation and amortization expense. The PSCW approved lower depreciation rates effective January 1, 2011, and we also had lower software amortization in 2011.

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Six Months 2011 Compared with Six Months 2010

Revenues

Regulated electric utility segment revenues decreased $17.8 million, driven by:

- An approximate $9 million decrease in revenues from wholesale customers. The decrease is primarily due to the closing of a customer s plant and lower non-fuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.
- An approximate $7 million decrease in revenues due to differences between the current WPS rate order and the previous rate order. An increase in revenues calculated on a per unit basis was more than offset by the impact of decoupling. The decoupling mechanism had a significant period-over-period impact due to changes in the current rate order that impacted the decoupling calculation. For more details on the current rate order, see Note 21, *Regulatory Environment* .
- An approximate $5 million decrease in market sales driven by a combination of lower natural gas prices, which lowered MISO prices for electricity, and higher production costs for certain WPS coal-fired plants. Production costs increased due to higher railroad transportation costs for coal beginning in 2011. Market sales do not directly impact margins. The revenues from these sales are used to reduce fuel and purchased power costs recovered through the power supply cost recovery mechanism.
- A partially offsetting approximate $3 million increase in revenues driven by a retail electric rate increase at UPPCO.

Margins

Regulated electric utility segment margins decreased $12.2 million, driven by:

- An approximate $14 million decrease in margins due to differences between the current WPS rate order and the previous rate order. An increase in margins calculated on a per unit basis was more than offset by the impact of decoupling. The decoupling mechanism had a significant period-over-period impact due to changes in the current rate order that impacted the decoupling calculation. For more details on the current rate order, see Note 21, *Regulatory Environment* .
- An approximate $3 million decrease in margins from wholesale customers. The decrease is primarily due to lower non-fuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.
- A partially offsetting approximate $3 million increase in margins driven by a retail electric rate increase at UPPCO.

Operating Income

Operating income at the regulated electric utility segment decreased $16.0 million, driven by the $12.2 million decrease in margins and a $3.8 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $2.8 million increase in maintenance expense. One of the main drivers of this increase was the timing of scheduled plant outages.
- A $2.7 million increase in the amortization of various regulatory deferrals. This increase was offset in revenues, resulting in no impact on earnings.

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- A $2.0 million increase in customer assistance expense related to payments made to the Focus on Energy program. The program helps residents and businesses install cost-effective, energy efficient, and renewable energy products.
- A $1.3 million increase in taxes other than income taxes due to increases in property taxes, payroll taxes, and gross receipts tax.
- A partially offsetting $4.9 million decrease in depreciation and amortization expense. The PSCW approved lower depreciation rates effective January 1, 2011, and we had lower software amortization in 2011.

Other Expense

Other expense increased $2.3 million, driven by an increase in interest expense for deferred compensation plans.

Electric Transmission Investment Segment Operations

Second Quarter 2011 Compared with Second Quarter 2010

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $0.7 million. The increase resulted from higher earnings from our approximate 34% ownership interest in ATC. We earn higher returns through ATC s continued investment in transmission equipment and facilities.

Six Months 2011 Compared with Six Months 2010

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $0.4 million. The increase resulted from higher earnings from our approximate 34% ownership interest in ATC. We earn higher returns through ATC s continued investment in transmission equipment and facilities. These higher earnings were partially offset by certain business development expenses incurred by ATC that were not recoverable in rates.

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Integrys Energy Services Nonregulated Segment Operations

(Millions, except natural gas sales volumes)	Three Months Ended June 30 2011	Three Months Ended June 30 2010 (1)	Change in 2011 over 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010 (1)	Change in 2011 over 2010
Revenues	**$ 336.3**	$ 401.2	(16.2)%	**$ 791.8**	$ 1,045.8	(24.3)%
Cost of fuel, natural gas, and purchased power	**289.7**	314.3	(7.8)%	**692.2**	952.5	(27.3)%
Margins	**46.6**	86.9	(46.4)%	**99.6**	93.3	6.8%
Margin Detail						
Realized retail electric margins	**24.0**	22.5(3)	6.7%	**44.3**	39.9(3)	11.0%
Realized wholesale electric margins	**(1.1)(2)**	(2.5)(4)	(56.0)%	**(1.4)(2)**	(1.6)(4)	(12.5)%
Realized energy asset margins	**7.7**	8.2	(6.1)%	**15.0**	16.3	(8.0)%
Fair value accounting adjustments	**7.3**	47.5	(84.6)%	**17.3**	4.4	293.2%
Electric and other margins	**37.9**	75.7	(49.9)%	**75.2**	59.0	27.5%
Realized retail natural gas margins	**6.9**	3.6	91.7%	**30.4**	32.8	(7.3)%
Realized wholesale natural gas margins	**(1.4)(2)**	(2.4)	(41.7)%	**1.4(2)**	(4.0)	N/A
Lower-of-cost-or-market inventory adjustments	**0.5**	1.4	(64.3)%	**0.6**	6.0	(90.0)%
Fair value accounting adjustments	**2.7**	8.6	(68.6)%	**(8.0)**	(0.5)	1,500.0%
Natural gas margins	**8.7**	11.2	(22.3)%	**24.4**	34.3	(28.9)%
Operating and maintenance expense	**29.4**	28.0	5.0%	**60.5**	58.8	2.9%
Restructuring expense	**0.8**	6.7	(88.1)%	**1.8**	9.2	(80.4)%
Net (gain) loss on Integrys Energy Services dispositions related to strategy change	**(0.1)**	(25.0)	(99.6)%	**(0.2)**	14.8	N/A
Depreciation and amortization	**3.2**	4.4	(27.3)%	**6.5**	9.0	(27.8)%
Taxes other than income taxes	**2.1**	0.6	250.0%	**3.9**	3.8	2.6%
Operating income (loss)	**11.2**	72.2	(84.5)%	**27.1**	(2.3)	N/A
Miscellaneous income	**0.4**	2.4	(83.3)%	**1.3**	2.9	(55.2)%
Interest expense	**(0.5)**	(1.4)	(64.3)%	**(1.0)**	(4.8)	(79.2)%
Other income (expense)	**(0.1)**	1.0	N/A	**0.3**	(1.9)	N/A
Income (loss) before taxes	**$ 11.1**	$ 73.2	(84.8)%	**$ 27.4**	$ (4.2)	N/A
Physically settled volumes						
Retail electric sales volumes in kwh	**2,997.0**	3,189.8(6)	(6.0)%	**5,949.5**	6,343.1(6)	(6.2)%
Wholesale electric sales volumes in kwh	**57.8(5)**	344.2	(83.2)%	**130.4(5)**	821.3	(84.1)%
Retail natural gas sales volumes in bcf	**23.9**	23.8(6)	0.4%	**72.4**	74.2(6)	(2.4)%
Wholesale natural gas sales volumes in bcf		3.8	(100.0)%		25.7	(100.0)%

kwh kilowatt-hours

bcf billion cubic feet

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(1)

Certain amounts were retrospectively adjusted due to a change in accounting policy in the fourth quarter of 2010. See Note 1, *Financial Information*, for more information.

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

(3) Amounts include negative margin of $1.4 million related to the settlement of supply contracts in connection with Integrys Energy Services strategy change.

(4) Amounts include negative margin of $3.8 million related to the settlement of supply contracts in connection with Integrys Energy Services strategy change.

(5) Primarily relates to electric generation assets.

(6) Includes physically settled volumes in markets that Integrys Energy Services no longer focuses on.

Second Quarter 2011 Compared with Second Quarter 2010

Revenues

Revenues decreased $64.9 million, driven by lower sales volumes resulting from Integrys Energy Services strategy change.

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Margins

Integrys Energy Services margins decreased $40.3 million. The significant items contributing to the change in margins were as follows:

Electric and Other Margins

Realized retail electric margins

Realized retail electric margins increased $1.5 million. A $1.4 million negative impact on margins in 2010 from the settlement of supply contracts drove this quarter-over-quarter increase. The change in pricing methodology and customer mix implemented as part of Integrys Energy Services strategy change led to increased margins in the majority of the markets that it continues to focus on. This increase was partially offset by a decrease in margins related to the sale of the Texas retail electric business in June 2010.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $40.2 million decrease in electric margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins increased $3.3 million. The increase was primarily due to the positive impact of negative margins recorded in the second quarter of 2010 related to the timing of natural gas storage activities. Higher sales volumes in the markets Integrys Energy Services continues to focus on also contributed to the increase.

Inventory accounting adjustments

Integrys Energy Services physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $0.9 million quarter-over-quarter decrease in margins from inventory adjustments was driven by a lower volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $5.9 million decrease in natural gas margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts.

Operating Income

Integrys Energy Services operating income decreased $61.0 million quarter over quarter, driven by the $40.3 million decrease in margins discussed above, and a $24.9 million decrease due to gains on Integrys Energy Services dispositions in 2010 related to its strategy change. This decrease was partially offset by a $5.9 million decrease in restructuring expense.

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Six Months 2011 Compared with Six Months 2010

Revenues

Revenues decreased $254.0 million, driven by lower sales volumes resulting from Integrys Energy Services strategy change.

Margins

Integrys Energy Services margins increased $6.3 million. The significant items contributing to the change in margins were as follows:

Electric and Other Margins

Realized retail electric margins

Realized retail electric margins increased $4.4 million. Overall, higher margins in the markets that Integrys Energy Services continues to focus on drove the increase. Most of these markets had higher sales volumes and positive results from the change in pricing methodology and customer mix that was implemented as part of Integrys Energy Services strategy change. The $1.4 million negative impact on margins in 2010 from the settlement of supply contracts also contributed to the period-over-period increase. The increase was partially offset by a decrease in margins related to the sale of the Texas retail electric business in June 2010.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $12.9 million increase in electric margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $2.4 million. In 2011 there were fewer opportunities to take advantage of natural gas price volatility and changes in market prices for natural gas storage and transportation capacity.

Inventory accounting adjustments

Integrys Energy Services   physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $5.4 million period-over-period decrease in margins from inventory adjustments was driven by a lower volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services   margins. Fair value adjustments caused a $7.5 million decrease in natural gas margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts.

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Operating Income

Integrys Energy Services operating income increased $29.4 million. The main drivers of the increase were a $15.0 million increase due to losses on Integrys Energy Services dispositions in 2010 related to its strategy change, a $7.4 million decrease in restructuring expense, and the $6.3 million increase in margins discussed above.

Other Income (Expense)

Integrys Energy Services other income increased $2.2 million. The increase was primarily due to a $3.8 million decrease in interest expense driven by reduced business size, as a result of Integrys Energy Services strategy change.

Holding Company and Other Segment Operations

(Millions)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Change in 2011 over 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010	Change in 2011 over 2010
Operating income	**$ 1.9**	$ 3.2	(40.6)%	**$ 3.6**	$ 2.6	38.5%
Other expense	**(7.9)**	(9.5)	(16.8)%	**(17.1)**	(21.9)	(21.9)%
Net loss before taxes	**$ (6.0)**	$ (6.3)	(4.8)%	**$ (13.5)**	$ (19.3)	(30.1)%

Second Quarter 2011 Compared with Second Quarter 2010

Operating Income

Operating income at the holding company and other segment decreased $1.3 million. The decrease was driven by lower intercompany fees charged to Integrys Energy Services related to a credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $1.6 million. Long-term debt interest expense decreased, driven by lower interest rates on debt financed in the fourth quarter of 2010. Lower average outstanding debt in 2011 also contributed to the decrease in interest expense.

Six Months 2011 Compared with Six Months 2010

Operating Income

Operating income at the holding company and other segment increased $1.0 million. Non-utility operating income increased, driven both by a price increase related to MERC s ServiceChoice program and higher hydroelectric operating income from UPPCO s non-utility Escanaba facility.

Other Expense

Other expense at the holding company and other segment decreased $4.8 million. The decrease was driven by lower amortization of credit facility fees in 2011. Lower long-term debt interest expense also contributed to the decrease.

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Provision for Income Taxes

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Effective Tax Rate	**45.9%**	35.8%	**38.8%**	42.1%

Second Quarter 2011 Compared with Second Quarter 2010

Our effective tax rate increased quarter over quarter. The increase primarily related to tax law changes in Michigan and Wisconsin. In the second quarter of 2011, Michigan replaced its business tax with a state income tax. In accounting for this tax law change, we expensed $4.2 million of deferred income taxes related to our nonregulated operations and adjustments related to our state unitary filings. Unitary filings are required by certain states to ensure income is properly reflected in the correct tax jurisdiction. The unitary adjustments reflect additional write-offs at the holding company for deferred income tax benefits held for our consolidated tax group. Also in the second quarter of 2011, the Wisconsin tax code was conformed to the federal tax code through passage of a budget bill, retroactive to December 2010. In accounting for this tax change, we expensed an additional $1.5 million of deferred income taxes in 2011 related to the Medicare Part D subsidy discussed below. See *Liquidity and Capital Resources, Other Future Considerations Recent Tax Law Changes* for more information.

Six Months 2011 Compared with Six Months 2010

Our effective tax rate decreased period over period. The 2010 federal health care reform eliminated the tax deduction for retiree prescription drug charges that are paid by employers and are offset by the receipt of a federal Medicare Part D subsidy. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform* for more information. As a result, we expensed $11.8 million of deferred income taxes during the first quarter of 2010. This decrease was partially offset by $5.7 million of additional expenses related to the second quarter 2011 tax law changes in Michigan and Wisconsin discussed above.

Discontinued Operations

Income from discontinued operations, net of tax, decreased $0.9 million. During the second quarter of 2011, we remeasured an unrecognized tax benefits liability related to the 2007 sale of Peoples Energy Production Company. The decrease represents additional state income tax expense related to the increase in our unrecognized tax benefits liability.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

During the six months ended June 30, 2011, net cash provided by operating activities was $588.2 million, compared with $758.4 million for the same period in 2010. The $170.2 million decrease was largely driven by:

•   A $198.9 million decrease in cash provided by working capital. The decrease is primarily due to a significant amount of cash generated in 2010 as a result of the Integrys Energy Services

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strategy change. Partially offsetting the impact from the strategy change was a $39.2 million decrease in income tax payments related to the 100% bonus depreciation allowed in 2011.

- A $47.2 million increase in contributions to pension and postretirement benefit plans.

- Partially offsetting the decreases in cash provided by operating activities was an increase in net income, adjusted for non-cash items.

Investing Cash Flows

Net cash used for investing activities was $122.5 million during the six months ended June 30, 2011, compared with $65.4 million for the same period in 2010. The $57.1 million increase in net cash used was driven by a reduction in proceeds received from the sale or disposal of assets. The proceeds received in 2010 primarily related to the Integrys Energy Services strategy change. Partially offsetting this change was an $8.3 million decrease in cash used to fund capital expenditures (discussed below).

Capital Expenditures

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

Reportable Segment (millions)	2011	2010	Change
Electric utility	**$ 38.6**	$ 43.2	$ (4.6)
Natural gas utility	**66.5**	52.1	14.4
Integrys Energy Services	**4.5**	10.0	(5.5)
Holding company and other	**4.9**	17.5	(12.6)
Integrys Energy Group consolidated	**$ 114.5**	$ 122.8	$ (8.3)

The decrease in capital expenditures at the holding company and other segment was primarily due to lower expenditures in 2011 related to software projects. The decrease in capital expenditures at the Integrys Energy Services segment was mainly due to decreased solar project expenditures. Partially offsetting these decreases was an increase in capital expenditures at the natural gas utility, primarily a result of the AMRP at PGL.

Financing Cash Flows

Net cash used for financing activities was $433.3 million during the six months ended June 30, 2011, compared with $504.4 million for the same period in 2010. The $71.1 million decrease in net cash used for financing activities was driven by:

- A $257.2 million decrease due to $57.6 million of net borrowings of commercial paper in 2011 compared with $199.6 million of net repayments in 2010.

- A $98.3 million decrease in payments related to the divestitures of the nonregulated wholesale electric and natural gas businesses. In 2010, $27.8 million was paid to the buyers upon the sale of these businesses. No such payments were made in 2011. The remaining $70.5 million decrease related to the settlement of certain contracts that were executed at the time of sale.

- Partially offsetting these decreases was a $239.1 million increase in the repayment of long-term borrowings.

Significant Financing Activities

We had outstanding commercial paper borrowings of $57.6 million and $12.5 million at June 30, 2011, and 2010, respectively. We had no short-term notes payable outstanding at June 30, 2011, and

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$10.0 million of short-term notes outstanding at June 30, 2011. See Note 9, *Short-Term Debt and Lines of Credit*, for more information.

For information on the issuance and redemption of long-term debt in 2011, see Note 10, *Long-Term Debt*.

From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. Beginning May 1, 2011, we began purchasing shares on the open market to meet the requirements of these plans.

Credit Ratings

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

Credit Ratings	**Standard & Poor s**	**Moody s**
Integrys Energy Group		
Issuer credit rating	BBB+	N/A
Senior unsecured debt	BBB	Baa1
Commercial paper	A-2	P-2
Credit facility	N/A	Baa1
Junior subordinated notes	BBB-	Baa2
WPS		
Issuer credit rating	A-	A2
First mortgage bonds	N/A	Aa3
Senior secured debt	A	Aa3
Preferred stock	BBB	Baa1
Commercial paper	A-2	P-1
Credit facility	N/A	A2
PGL		
Issuer credit rating	BBB+	A3
Senior secured debt	A-	A1
Commercial paper	A-2	P-2
NSG		
Issuer credit rating	BBB+	A3
Senior secured debt	A	A1

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

On January 21, 2011, Standard & Poor s revised the outlook for Integrys Energy Group, PGL, and NSG to positive from stable. According to Standard & Poor s, the revised outlook reflects their view that there is at least a one-in-three probability that we will improve our business risk profile over the intermediate term and maintain our improved financial measures despite our increased capital spending. WPS s outlook remains stable.

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Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of June 30, 2011, including those of our subsidiaries.

(Millions)	Total Amounts Committed	2011	Payments Due By Period 2012 to 2013	2014 to 2015	2016 and Thereafter
Long-term debt principal and interest payments (1)	$ 3,198.7	$ 206.4	$ 765.0	$ 376.2	$ 1,851.1
Operating lease obligations	50.3	6.1	16.9	6.7	20.6
Commodity purchase obligations (2)	2,579.4	409.3	1,042.7	449.7	677.7
Purchase orders (3)	482.5	479.5	3.0		
Pension and other postretirement funding obligations (4)	603.4	23.9	324.9	194.4	60.2
Capital contributions to equity method investment	2.6	2.6			
Total contractual cash obligations	$ 6,916.9	$ 1,127.8	$ 2,152.5	$ 1,027.0	$ 2,609.6

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

(2) Energy and related commodity supply contracts at Integrys Energy Services included as part of commodity purchase obligations are generally entered into to meet obligations to deliver energy and related products to customers. The utility subsidiaries expect to recover the costs of their contracts in future customer rates.

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2013.

The table above does not reflect payments related to the manufactured gas plant remediation liability of $638.9 million at June 30, 2011, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 12, *Commitments and Contingencies*, for more information about environmental liabilities. The table also does not reflect any payments for the June 30, 2011, liability of $22.4 million related to uncertain tax positions, as the amount and timing of the payments are uncertain. See Note 11, *Income Taxes*, for more information on uncertain tax positions.

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Capital Requirements

As of June 30, 2011, our subsidiaries capital expenditures for the three-year period 2011 through 2013 were expected to be as follows:

(Millions)		
WPS		
Environmental projects	$	**348.7**
Electric and natural gas distribution projects		**123.5**
Electric and natural gas delivery and customer service projects		**32.8**
Other projects		**123.9**
UPPCO		
Repairs and safety measures at hydroelectric facilities		**16.7**
Other projects		**35.5**
MGU		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**34.8**
MERC		
Natural gas pipe distribution system and other projects		**53.8**
PGL		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects *		**684.3**
NSG		
Natural gas pipe distribution system and other projects		**77.9**
Integrys Energy Services		
Solar and other projects		**71.1**
IBS		
Corporate services infrastructure projects		**90.8**
Total capital expenditures	$	**1,693.8**

* Includes approximately $300 million of incremental expenditures related to the AMRP at PGL in 2011, 2012, and 2013. On January 21, 2010, the ICC approved a rider mechanism to allow PGL to recover these incremental costs. See Note 21, *Regulatory Environment*, for more information.

We expect to provide capital contributions to INDU Solar Holdings, LLC, (not included in the above table) of approximately $45 million in both 2011 and 2012. INDU Solar Holdings was created in October 2010, through wholly owned subsidiaries of both Integrys Energy Services and Duke Energy Generation Services, to build and finance distributed solar projects throughout the United States.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $10 million in both 2011 and 2012, and $5 million in 2013.

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

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Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management policies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage the liquidity and capital resource needs of the business segments. We plan to meet our capital requirements for the period 2011 through 2013 primarily through internally generated funds (net of forecasted dividend payments) and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth. We believe we have adequate financial flexibility and resources to meet our future needs.

Under an existing shelf registration statement, we may issue debt, equity, certain types of hybrid securities, and other financial instruments. The specific terms and conditions of the securities are determined before the securities are issued.

At June 30, 2011, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future.

See Note 9, *Short-Term Debt and Lines of Credit*, for more information on credit facilities and other short-term credit agreements, including short-term debt covenants. See Note 10, *Long-Term Debt*, for more information on long-term debt and related covenants.

Other Future Considerations

Decoupling

In certain jurisdictions, decoupling mechanisms have been implemented. These mechanisms allow utilities to adjust rates going forward to recover or refund all or a portion of the differences between the actual and authorized margin per customer impact of changes in volumes. The mechanisms do not adjust for changes in volumes resulting from changes in customer count, nor do they cover all customer classes.

- Decoupling for residential and small commercial and industrial sales was approved by the ICC on a four-year trial basis for PGL and NSG, effective March 1, 2008. Interveners, including the Illinois Attorney General, oppose decoupling and have appealed the ICC s approval. PGL and NSG actively support the ICC s decision to approve decoupling. PGL and NSG requested in their February 15, 2011 rate case filing that decoupling be approved on a permanent basis. The ICC Staff has preliminarily indicated that they support making the decoupling mechanism permanent for PGL and NSG, but the interveners continue to oppose decoupling.

- Decoupling for natural gas and electric residential and small commercial and industrial sales was approved by the PSCW on a four-year trial basis for WPS, effective January 1, 2009. This decoupling mechanism includes an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are included in rates upon approval in a rate order.

- Decoupling for UPPCO was approved for the majority of customer groups by the MPSC, effective January 1, 2010.

- The MPSC granted an order, effective January 1, 2010, approving a decoupling mechanism for MGU as a pilot program, covering residential and small commercial and industrial customers. The decoupling mechanism does not adjust for weather-related usage.

- In Minnesota, MERC proposed a decoupling mechanism in its November 30, 2010 general rate case filing.

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See Note 21, *Regulatory Environment*, for more information.

Climate Change

The EPA began regulating greenhouse gas emissions under the CAA in January 2011, by applying the BACT requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In December 2010, the EPA announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. The EPA plans to propose these standards in 2011 and finalize them in 2012. Currently there is no applicable federal or state legislation pending that specifically addresses greenhouse gas emissions.

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

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

Property Tax Assessment on Natural Gas

Our subsidiaries and natural gas retailers purchase storage services from pipeline companies on interstate systems. Once a shipper delivers natural gas to the pipeline s system, it cannot be physically traced back to the shipper. Some states tax natural gas as personal property. These states have recently sought to assess personal property tax obligations on natural gas quantities held as working natural gas in facilities located within their jurisdiction. Since the pipeline does not have title to the working natural gas inventory in these facilities, the states impose the tax on the shippers as of the assessment date. The tax is based on allocated quantities. Shippers that are being assessed a tax are actively protesting these property tax assessments. MERC is currently pursuing a protest through litigation in Kansas. PGL successfully won its protest in Texas when, in April 2011, the U.S. Supreme Court denied a petition for review of the Texas Appellate Court s decision in favor of PGL. This resolved the pending Texas litigation and, barring adverse legal developments, we expect that it will prevent future assessments in Texas taxing districts. PGL is pursuing refunds of amounts previously paid in Texas.

Federal Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (HCR) were signed into law. HCR contains various provisions that will affect the cost of providing health care coverage to our active and retired employees and their dependents. Although these provisions become effective at various times over the next 10 years, some provisions that affect the cost of providing benefits to retirees were reflected in our financial statements in 2010.

Beginning in 2013, a provision of HCR will eliminate the tax deduction for employer-paid postretirement prescription drug charges to the extent those charges will be offset by the receipt of a federal Medicare Part D subsidy. As a result, we eliminated $11.8 million of our deferred tax asset related to postretirement benefits in 2010. Of this amount, $10.8 million flowed through to net income as a component of income tax expense in 2010. The remaining $1.0 million was deferred for regulatory

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recovery at UPPCO. We have sought, or expect to seek, rate recovery for the income impacts of this tax law change in the majority of our jurisdictions. If recovery in rates becomes probable, income tax expense will be reduced in that period. We are not currently able to predict how much will be recovered in rates.

In the second quarter of 2011, Wisconsin signed a two-year budget bill. The bill conformed the Wisconsin tax code to the federal tax code, retroactive to December 2010 (discussed below). In accounting for this tax law change, in the second quarter of 2011, we expensed an additional $1.5 million of deferred income taxes related to the Medicare Part D subsidy.

Other provisions of HCR include the elimination of certain annual and lifetime maximum benefits and the broadening of plan eligibility requirements. It also includes the elimination of pre-existing condition restrictions, an excise tax on high-cost health plans, changes to the Medicare Part D prescription drug program, and numerous other changes. We participate in the Early Retiree Reinsurance Program that became effective on June 1, 2010. We continue to assess the extent to which the provisions of the new law will affect our future health care and related employee benefit plan costs.

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

The Dodd-Frank Act was signed into law in July 2010. The majority of the implementation rules will be finalized and become effective over the 18 months following the signing of the act. Depending on the final rules, certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. Final rules for these provisions are expected in 2011. We are monitoring developments related to this act and their impacts on our future financial results.

Recent Tax Law Changes

Federal

In December 2010, President Obama signed into law The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This act includes tax incentives, such as an extension and increase of bonus depreciation, the extension of the research and experimentation credit, and the extension of treasury grants in lieu of claiming the ITC or production tax credit for certain renewable energy investments. In September 2010, President Obama signed into law the Small Business Jobs Act of 2010. This act includes tax incentives, such as an extension to bonus depreciation and changes to listed property, that affect us. We anticipate that these tax law changes will likely result in $140.0 million to $240.0 million of reduced cash payments for taxes during 2011 and 2012. These incentives may also reduce utility rate base and, thus, future earnings relative to prior expectations. We are evaluating the most appropriate manner to deploy the additional cash, which may include, among other things, making incremental contributions to our various employee benefit plans and funding additional capital investments.

Illinois

In January 2011, the Taxpayer Accountability and Budget Stabilization Act was enacted in Illinois. This act increases the corporate combined income tax rate from 7.3% to 9.5% retroactive to January 1, 2011. The rate decreases to 7.75% after 2014 and returns to 7.3% after 2024. We adjusted deferred taxes to reflect the changes in the tax rate in the first quarter of 2011. Due to the effects of regulation, and the timing of the February 2011 rate filings for PGL and NSG, we do not expect a material impact on income from this legislation.

Michigan

In May 2011, Governor Snyder signed legislation that replaced Michigan s business tax with a state income tax, effective January 1, 2012. In accounting for this tax law change, in the second quarter of

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2011, we expensed $4.2 million of deferred income taxes related to our nonregulated operations and our unitary filings. We deferred an additional $4.2 million for recovery in future rates.

Wisconsin

In June 2011, Governor Walker signed a two-year budget bill. The bill conformed the Wisconsin tax code to the federal tax code, retroactive to December 2010. In accounting for this tax law change, in the second quarter of 2011, we expensed an additional $1.5 million of deferred income taxes related to the Medicare Part D subsidy. The legislation also contains favorable provisions related to the carryforward of net operating losses prior to 2008. We are continuing to analyze the implications of this bill.

Illinois Coal-to-Gas Plant Legislation

Prior legislation vetoed by Governor Quinn in March 2011 has been replaced by Senate Bill (SB) 1533 and SB 2169. SB 1533 would require PGL and NSG either to enter into 30-year purchase contracts for manufactured gas produced from a coal and petroleum coke plant to be built on the south side of Chicago or to elect to file biennial rate proceedings before the ICC by August 1 in 2012, 2014, and 2016. The plant would sell its entire offput to the four largest Illinois natural gas utilities in amounts allocated based on therms sold in 2008 by these utilities. No utility would be required to take more than 42% of the total plant offput. A decision to elect to file biennial rate proceedings before the ICC must be made within 60 days of the law s effective date. SB 2169 is similar legislation for a manufactured gas project expected to be located in Jefferson County, Illinois. It would require PGL and NSG either to enter into 10-year purchase contracts, with the offput of the project allocated among the four largest Illinois natural gas utilities based on therms sold in 2008, or agree to biennial rate filings made by September 30 in 2012, 2014, and 2016. No utility would be required to take more than 42% of the total plant offput. Both bills were signed by Governor Quinn in the third quarter of 2011.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies for new critical accounting estimates and other significant changes and have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2010, are still current and that there have been no significant changes, except as follows:

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carry a goodwill balance as of April 1, 2011. No impairment was recorded as a result of these tests. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. The fair value was calculated using an equal weighting of the income approach and the market approach.

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

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

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

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

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

The fair values calculated in the first step of the test for MGU, MERC, PGL, and NSG exceeded the carrying values by approximately 6%-17%. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, that would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test.

Change in key inputs (in basis points)	**MGU**	**MERC**	**PGL**	**NSG**
Discount rate	75	150	175	450
Terminal year return on equity	(195)	(310)	(487)	(810)
Terminal year growth rate	(100)	(225)	N/A*	N/A*

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We have potential market risk exposure related to commodity price risk (including regulatory recovery risk), interest rate risk, and equity return and principal preservation risk. We are also exposed to other significant risks due to the nature of our subsidiaries businesses and the environment in which we operate. We have risk management policies in place to monitor and assist in controlling these risks and may use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

To measure commodity price risk exposure, we employ a number of controls and processes, including a value-at-risk (VaR) analysis of certain of our exposures. Integrys Energy Services VaR is calculated using non-discounted positions with a delta-normal approximation based on a one-day holding period and a 95% confidence level, as well as a ten-day holding period and 99% confidence level. For further explanation of our VaR calculation, see our 2010 Annual Report on Form 10-K.

The VaR for Integrys Energy Services open commodity positions at a 95% confidence level with a one-day holding period is presented in the following table:

(Millions)	2011	2010
As of June 30	$ 0.1	$ 0.3
Average for 12 months ended June 30	0.2	0.5
High for 12 months ended June 30	0.3	0.7
Low for 12 months ended June 30	0.1	0.3

The VaR for Integrys Energy Services open commodity positions at a 99% confidence level with a ten-day holding period is presented below:

(Millions)	2011	2010
As of June 30	$ 0.6	$ 1.4
Average for 12 months ended June 30	1.1	2.2
High for 12 months ended June 30	1.5	3.3
Low for 12 months ended June 30	0.6	1.4

The average, high, and low amounts were computed using the VaR amounts at each of the four quarter ends.

Interest Rate Risk

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

Based on the variable rate debt outstanding at June 30, 2011, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $1.4 million. Comparatively, based on the variable rate debt outstanding at June 30, 2010, an increase in interest rates of 100 basis points would have increased annual interest expense by $1.5 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Other than the above-mentioned changes, our market risks have not changed materially from the market risks reported in our 2010 Annual Report on Form 10-K.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of Integrys Energy Group s disclosure controls and procedures (as defined by Securities Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based upon that evaluation, management, including our Chief Executive Officer and Chief Financial Officer, has concluded that Integrys Energy Group s disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended June 30, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For information on material legal proceedings and matters, see Note 12, *Commitments and Contingencies*.

Item 1A. Risk Factors

There were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2010 Annual Report on Form 10-K, which was filed with the SEC on February 24, 2011.

Item 6. Exhibits

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

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SIGNATURE

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

Integrys Energy Group, Inc.

Date: August 3, 2011

/s/ Diane L. Ford
Diane L. Ford
Vice President and Corporate Controller

(Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS ENERGY GROUP

EXHIBIT INDEX TO FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2011

Exhibit No.	**Description**
3.1	Amendments to the Integrys Energy Group, Inc. By-laws effective May 11, 2011 (Incorporated by reference to Exhibit 3.1 to Integrys Energy Group s Form 8-K filed May 16, 2011)
3.2	Integrys Energy Group, Inc. By-laws as in effect May 11, 2011 (Incorporated by reference to Exhibit 3.2 to Integrys Energy Group s Form 8-K filed May 16, 2011)
10.1	Three Year Credit Agreement with Citibank, N.A., The Bank of Nova Scotia and U.S. Bank National Association, Wells Fargo Bank, National Association, and Wells Fargo Securities, LLC and Citigroup Global Markets, Inc., dated as of May 17, 2011 (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group s Form 8-K filed May 23, 2011)
10.2	Five Year Credit Agreement with Citibank, N.A., The Bank of Nova Scotia and U.S. Bank National Association, Wells Fargo Bank, National Association, and Wells Fargo Securities, LLC and Citigroup Global Markets, Inc., dated as of May 17, 2011 (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group s Form 8-K filed May 23, 2011)
12	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101 *	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended June 30, 2011, filed on August 3, 2011, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Balance Sheets, (iii) the Condensed Consolidated Statements of Cash Flows, (iv) the Condensed Notes To Financial Statements, and (v) document and entity information

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* In accordance with Rule 406T of Regulation S-T, the information in these exhibits shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such filing.