INTEGRYS ENERGY GROUP, INC.
Form 10-K
March 01, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K
(Mark One)

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

For the fiscal year ended December 31, 2012
OR

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

For the transition period from ________________ to ___________________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-11337	INTEGRYS ENERGY GROUP, INC. (A Wisconsin Corporation) 130 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $1 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [

]

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ]   No [X]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.

$4,430,861,866 as of June 30, 2012

Number of shares outstanding of each class of common stock, as of
February 20, 2013

Common Stock, $1 par value, 78,400,088 shares

DOCUMENT INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Integrys Energy Group, Inc. Annual Meeting of Shareholders to be held on May 16, 2013 are incorporated by reference into Part III.

INTEGRYS ENERGY GROUP, INC.

ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2012

TABLE OF CONTENTS

Acronyms Used in this Annual Report on Form 10-K

AFUDC	Allowance for Funds Used During Construction
AMRP	Accelerated Natural Gas Main Replacement Program
ASC	Accounting Standards Codification
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC
LIFO	Last-in, First-out
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midwest Independent Transmission System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utility Commission
N/A	Not Applicable
NSG	North Shore Gas Company
OCI	Other Comprehensive Income
PELLC	Peoples Energy, LLC (formerly known as Peoples Energy Corporation)
PGL	The Peoples Gas Light and Coke Company
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WDNR	Wisconsin Department of Natural Resources
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Forward-Looking Statements

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

Forward-looking statements involve a number of risks and uncertainties. Some risks that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2012, and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards;
- Other federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries' liquidity and financing efforts;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;
- The ability to retain market-based rate authority;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The impact of unplanned facility outages;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer use, customer growth, and our ability to adequately forecast energy use for our customers;
- Potential business strategies, including mergers, acquisitions, and construction or disposition of assets or businesses, which cannot be assured to be completed timely or within budgets;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries' counterparties, affiliates, and customers to meet their obligations;
-

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

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

PART I

ITEM 1. BUSINESS

A. GENERAL

In this report, when we refer to "us, " "we, " "our, " or "ours, " we are referring to Integrys Energy Group, Inc. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, including financial and geographic information about each reportable business segment, see Note 26, "Segments of Business," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations."

Integrys Energy Group, Inc.

We are a diversified energy holding company headquartered in Chicago, Illinois. We were incorporated in Wisconsin in 1993. Our wholly owned subsidiaries provide products and services in both the regulated and nonregulated energy markets. In addition, we have a 34% equity interest in ATC (an electric transmission company operating in Wisconsin, Michigan, Minnesota, and Illinois). We have five reportable segments, which we discuss below.

Facilities

For information regarding our facilities, see Item 2, "Properties." For our utility and nonregulated plant asset book value, see Note 5, "Property, Plant, and Equipment."

Available Information

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, registration statements, and any amendments to these documents are available, free of charge, on our website, www.integrysgroup.com, as soon as reasonably practicable after they are filed with or furnished to the SEC. Reports, statements, and amendments posted on our website do not include access to exhibits and supplemental schedules electronically filed with the reports, statements, or amendments. We are not including the information contained on or available through our website as a part of, or incorporating such information by reference into, this Annual Report on Form 10-K.

You may obtain materials we filed with or furnished to the SEC at the SEC Public Reference Room at 100 F Street, NE, Washington, DC 20549. To obtain information on the operation of the Public Reference Room, you may call the SEC at 1-800-SEC-0330. You may also view our reports, proxy and registration statements, and other information (including exhibits) filed or furnished electronically with the SEC, at the SEC's website at www.sec.gov.

B. REGULATED NATURAL GAS UTILITY OPERATIONS

Our natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS. MERC and MGU, both Delaware corporations, began operations upon the acquisition of existing natural gas distribution operations in Minnesota and Michigan, respectively, in July 2006 and April 2006, respectively. NSG and PGL, both Illinois corporations, began operations in 1900 and 1855, respectively. We acquired NSG and PGL in February 2007 in the PELLC merger. WPS, a Wisconsin corporation, began operations in 1883.

Our regulated natural gas utilities provide service to approximately 1,690,000 residential, commercial and industrial, transportation, and other customers. Our customers are located in Chicago and the northern suburbs of Chicago, northeastern Wisconsin and an adjacent portion of Michigan's Upper Peninsula, various cities and communities throughout Minnesota, and the southern portion of lower Michigan.

Natural Gas Supply

Our regulated natural gas utilities manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns at the lowest reasonable cost.

Our regulated natural gas supply requirements are met through a combination of fixed price purchases, index price purchases, contracted and owned storage, peak-shaving facilities, and natural gas supply call options. Our regulated natural gas subsidiaries contract for fixed-term firm natural gas supply each year (in the United States and Canada) to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, our regulated natural gas utilities purchase additional natural gas supply on the monthly and daily spot markets.

For more information on our regulated natural gas utility supply and transportation contracts, see Note 15, "Commitments and Contingencies."

Our regulated natural gas utilities own two storage fields and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, thus providing a hedge against supply cost volatility. Our regulated natural gas utilities contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our regulated natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our regulated natural gas utilities when negotiating new agreements for transportation and storage services. Our regulated natural gas utilities further reduce their supply cost volatility through the use of financial instruments such as commodity futures, swaps, and options as part of their hedging program.

PGL owns and operates an underground natural gas storage reservoir in central Illinois (Manlove Field) and a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in PGL's regulatory rate base. PGL also uses a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to its wholesale customers. Customers deliver natural gas to PGL through an injection, and PGL later returns the natural gas to the customers when needed through a withdrawal. Title to the natural gas does not transfer to PGL. Therefore, all natural gas related only to the hub remains customer-owned. PGL recognizes service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

The table below is a rollforward of PGL's natural gas in storage balances related to the natural gas hub as well as natural gas hub service fees collected from wholesale customers:

Thousands of Dekatherms (MDth)	2012	2011	2010
Beginning Balance, January 1	5,261	5,156	5,187
Injections	7,000	7,000	7,010
Withdrawals	(7,021)	(6,895)	(7,041)
Ending Balance, December 31	5,240	5,261	5,156

(Millions)	2012	2011	2010
Natural gas hub service fees	$3.9	$5.4	$10.3

Our regulated natural gas utilities had adequate capacity to meet all firm natural gas demand obligations during 2012 and expect to have adequate capacity to meet all firm demand obligations during 2013. Our regulated natural gas utilities' forecasted design peak-day throughput is 3,690 MDth for the 2012 through 2013 heating season.

The sources of our deliveries to customers (including transportation customers) in MDth for regulated natural gas utility operations were as follows:

(MDth)	2012	2011	2010
Natural gas purchases	184,188	217,288	204,794
Natural gas purchases for electric generation	2,215	1,780	1,389
Customer-owned natural gas received	176,598	181,021	172,180
Underground storage, net	2,749	(1,425)	3,494
Hub fuel in kind *	179	180	176
Liquefied petroleum gas (propane)	1	1	4
Owned storage cushion injection	(1,097)	(1,098)	(1,094)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted-for natural gas	(8,037)	(10,809)	(7,544)
Total	356,796	386,938	373,399

* This delivered natural gas was originally provided by hub customers whose contract requires them to provide additional natural gas to compensate for unaccounted-for natural gas in future deliveries.

Regulatory Matters

Our regulated natural gas utility retail rates are regulated by the ICC, PSCW, MPSC, and the MPUC. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Sales are made and services are rendered by the regulated natural gas utilities pursuant to rate schedules on file with the respective commissions. These rate schedules contain various service classifications, which largely reflect customers' different uses and levels of consumption. Our regulated natural gas utilities bill customers for the distribution of natural gas as well as for a natural gas charge representing third-party costs for purchasing, transporting, and storing natural gas. This charge also includes gains, losses, and costs incurred under hedging programs, the amount of which is also subject to applicable commission authority. Prudently incurred natural gas costs are passed through to customers in current rates and, therefore, have no impact on margins. Commissions in respective jurisdictions conduct annual proceedings regarding the reconciliation of revenues from the natural gas charge and related natural gas costs.

Almost all of the natural gas our regulated natural gas utilities distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services, including PGL's natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. Under United States Department of Transportation regulations, the state commissions are responsible for monitoring our regulated natural gas utilities' safety compliance programs for our pipelines under 49 Code of Federal Regulations (CFR) Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

All of our regulated natural gas utility subsidiaries are required to provide service and grant credit (with applicable deposit requirements) to customers within their service territories. Our regulated natural gas utilities are generally not allowed to discontinue service during winter moratorium months to residential customers who do not pay their bills. The Federal and certain state governments have legislation that provides for a limited amount of funding for assistance to low-income customers of the utilities.

See Note 25, "Regulatory Environment," for information regarding rate cases, decoupling mechanisms, and bad debt recovery mechanisms in place at the regulated natural gas utilities.

Other Matters
Seasonality

The natural gas throughput of our regulated natural gas utilities is generally higher during the winter months because the heating requirements of customers are temperature driven. During 2012, the regulated natural gas utility segment recorded approximately 64% of its revenues in January, February, March, November, and December.

Competition

Although our natural gas retail rates are regulated by various commissions, the regulated natural gas utilities still face competition from other entities and other forms of energy available to consumers in varying degrees, particularly for large commercial and industrial customers who have the ability to switch between natural gas and alternate fuels. Due to the volatility of energy commodity prices, our regulated natural gas utilities have seen customers with dual fuel capability switch to alternate fuels for short periods of time, then switch back to natural gas as market rates change.

Our regulated natural gas utilities offer natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our regulated natural gas utilities' distribution systems to transport the natural gas to their facilities. Our regulated natural gas utilities still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has no impact on our regulated natural gas utilities' segment net income, as it is offset by an equal reduction to natural gas costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Working Capital Requirements

The working capital needs of our regulated natural gas utility operations vary significantly over time due to volatility in levels of natural gas inventories and the price of natural gas. Our regulated natural gas utilities' working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our regulated natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

C. REGULATED ELECTRIC UTILITY OPERATIONS

The electric utility segment includes the regulated electric utility operations of UPPCO and WPS. UPPCO, a Michigan corporation, began operations in 1884. We acquired UPPCO in September 1998.

The regulated electric utility operations of UPPCO and WPS provide service to approximately 495,000 residential, commercial and industrial, wholesale, and other customers. WPS's customers are located in northeastern Wisconsin and an adjacent portion of Michigan's Upper Peninsula. UPPCO's customers are located in Michigan's Upper Peninsula. Wholesale electric service is provided to various customers, including municipal utilities, electric cooperatives, energy marketers, other investor-owned utilities, and municipal joint action agencies. Beginning in 2012, UPPCO no longer provides service to wholesale electric customers due to the expiration of its remaining wholesale electric contracts in 2011. In 2012, retail electric revenues accounted for 87.5% of total electric revenues, while wholesale electric revenues accounted for 12.5% of total electric revenues.

In 2012, WPS reached a firm net design peak of 2,347 megawatts on July 16. At the time of this summer peak, WPS's total firm resources (i.e., generation plus firm purchases) totaled 3,173 megawatts. The summer period is the most relevant for WPS's regulated electric utility capacity due to the air conditioning requirements of its customers.

The PSCW requires WPS to maintain a planning reserve margin above its projected annual peak demand forecast to help ensure reliability of electric service to its customers. The PSCW has a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO under Module E of its Open Access Transmission and Energy Markets Tariff. MISO has a 16.7% reserve margin requirement from January 1 through May 31, 2013, and 14.2% for the remainder of 2013. The MPSC does not have minimum guidelines for future supply reserves.

In 2012, UPPCO reached a firm net design peak of 105 megawatts on July 5. At the time of this peak, UPPCO's total firm resources totaled 195 megawatts. The MPSC does not have minimum guidelines for future supply reserves; however, the MISO short-term planning reserve margin requirements described above also apply to UPPCO.

WPS and UPPCO expect future supply reserves to meet the minimum planning reserve margin requirements for 2013. WPS and UPPCO had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2012 and expect to have adequate capacity to meet all obligations during 2013.

Electric Supply

Both WPS and UPPCO are members of MISO, a FERC-approved, independent, nonprofit organization, which operates a financial and physical electric wholesale market in the Midwest. WPS and UPPCO offer their generation and bid their customer load into the MISO market. MISO evaluates WPS's, UPPCO's, and other market participants' energy offers into, and subsequent withdrawals from, the system to economically dispatch electricity within the system. MISO settles the participants' offers and bids based on locational marginal prices, which are market-driven values based on the specific time and location of the purchase and/or sale of energy.

Electric Generation and Supply Mix

The sources of our electric utility supply were as follows:

(Millions) Energy Source (kilowatt-hours)	2012	2011	2010
Company-owned generation units			
Coal	7,390.1	8,634.5	10,232.9
Hydroelectric	251.2	348.9	306.5
Wind	330.6	309.3	287.7
Natural gas, fuel oil, and tire derived fuel	176.1	135.8	105.4
Total company-owned generation units	8,148.0	9,428.5	10,932.5
Power purchase contracts			
Nuclear (Kewaunee Power Station)	2,655.5	2,674.4	2,940.8
Natural gas (Fox Energy Center, LLC * and Combined Locks Energy Center, LLC)	2,892.6	1,593.9	608.4
Hydroelectric	392.6	570.7	526.7
Wind	220.1	210.6	149.1
Other	1,580.5	235.8	205.5
Total power purchase contracts	7,741.3	5,285.4	4,430.5

Purchased power from MISO	849.3	1,605.2	781.9
Purchased power from other	106.3	100.1	342.9
Total purchased power	8,696.9	6,990.7	5,555.3
Opportunity sales			
Sales to MISO	(1,800.6)	(1,242.0)	(734.5)
Net sales to other	(128.4)	(64.6)	(248.4)
Total opportunity sales	(1,929.0)	(1,306.6)	(982.9)
Total electric utility supply	14,915.9	15,112.6	15,504.9

* In September 2012, WPS entered into an agreement to acquire all of the equity interests in Fox Energy Company LLC. The purchase includes the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility located in Wisconsin, along with associated contracts. WPS currently supplies natural gas for the facility and purchases 500 megawatts of capacity and the associated energy output under a tolling arrangement. The transaction is expected to close by the end of March 2013.

Fuel Costs

The cost of fuel per generation of one million British thermal units was as follows:

Fuel Type	2012	2011	2010
Coal	$2.52	$2.44	$2.05
Natural gas	3.97	5.64	6.28
Fuel oil	26.12	21.24	18.44

Coal Supply

Coal is the primary fuel source for WPS's electric generation facilities. WPS's regulated fuel portfolio strategy is to maintain a 35- to 45-day supply of coal at each plant site. Currently the coal supply is higher than the portfolio strategy due to lower coal burning rates as a result of decreased natural gas prices and economic conditions. The majority of the coal is purchased from Powder River Basin mines located in Wyoming. This low sulfur coal has been WPS's lowest cost coal source of any of the subbituminous coal-producing regions in the United States. Historically, WPS has purchased coal directly from the producer for its wholly owned plants. WPS also purchases the coal for the jointly owned Weston 4 plant, and Dairyland Power Cooperative reimburses WPS for its share of the coal costs. Wisconsin Power and Light Company purchases coal for the jointly owned Edgewater and Columbia plants and is reimbursed by WPS for its share of the coal costs. At December 31, 2012, WPS had coal transportation contracts in place for 100% of its 2013 coal transportation requirements. For more information on coal purchases and coal deliveries under contract, see Note 15, "Commitments and Contingencies."

Power Purchase Agreements

Our electric utilities enter into short-term and long-term power purchase agreements to meet a portion of their electric energy supply needs. For more information on power purchase obligations, see Note 15, "Commitments and Contingencies."

Regulatory Matters

WPS's retail electric rates are regulated by the PSCW and the MPSC. UPPCO's retail electric rates are regulated by the MPSC. The FERC regulates wholesale electric rates for WPS and UPPCO. WPS and UPPCO must also comply with mandatory electric system reliability standards developed by the North American Electric Reliability Corporation (NERC), the electric reliability organization certified by the FERC. The Midwest Reliability Organization is responsible for the enforcement of NERC’s standards for WPS and UPPCO.

The PSCW sets rates through its ratemaking process, which is based on recovery of operating costs and a return on invested capital. One of the cost recovery components is fuel and purchased power, which is governed by a fuel window mechanism, as described in Note 1(f), "Summary of Significant Accounting Policies – Revenues and Customer Receivables." The MPSC and the FERC ratemaking processes are similar to those of the PSCW, with the exception of fuel and purchased power, which are recovered on a one-for-one basis.

See Note 25, "Regulatory Environment," for information regarding the rate cases and decoupling mechanisms of our electric utilities.

Hydroelectric Licenses

WPS, UPPCO, and WRPC (a company in which WPS has 50% ownership) have long-term licenses from the FERC for their hydroelectric facilities.

Other Matters
Seasonality

Our electric utility sales in Wisconsin are generally higher during the summer months due to the air conditioning requirements of customers. Our regulated electric utility sales in Michigan do not follow a significant seasonal trend due to cooler climate conditions in the Upper Peninsula of Michigan.

Competition

The retail electric utility market in Wisconsin is regulated by the PSCW. Retail electric customers currently do not have the ability to choose their electric supplier. In order to increase sales, utilities work to attract new customers into their service territories. As a result, there is competition among utilities to keep energy rates low. Wisconsin utilities have continued to refine regulated tariffs in order to pass on the true cost of electricity to each class of customer by reducing or eliminating rate subsidies among different ratepayer classes. Although Wisconsin electric energy markets are regulated, utilities still face competition from other energy sources, such as self-generation by large industrial customers and alternative energy sources.

Michigan electric energy markets are open to competition. During 2012, alternate energy suppliers entered UPPCO's service territory in the Upper Peninsula of Michigan, creating an active competitive market.

D. INTEGRYS ENERGY SERVICES

Integrys Energy Services, a Wisconsin corporation, was established in 1994. Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.

Integrys Energy Services and its subsidiaries market electricity and natural gas in various retail markets, serving commercial and industrial customers, as well as direct and "aggregated" small commercial and residential customers. Aggregated customers are municipalities, associations, or groups of customers that have joined together to negotiate the purchase of electricity or natural gas as a larger group. At December 31, 2012, Integrys Energy Services was serving aggregated customers in Ohio and Illinois. In December 2012, Integrys Energy Services was selected by the City of Chicago to be the sole electric supplier for Chicago's electric aggregation program.

Integrys Energy Services invests in and promotes renewable energy, primarily distributed solar, which it believes is important to the future of the energy industry. Clean, renewable, and efficient energy sources are developed, acquired, owned, and operated by Integrys Energy Services. Integrys Energy Services assists customers with selecting an energy solution that meets their needs and collaborates with developers of energy projects to overcome challenges with integrating the technical, regulatory, and financial aspects of their projects.

Integrys Energy Services has invested in a joint venture with Duke Energy Generation Services to build and finance distributed solar projects throughout the United States. Duke Energy Generation Services and Integrys Energy Services equally fund the necessary equity capital for construction and ownership of the solar projects.

Integrys Energy Services uses physical and financial derivative instruments, including forwards, futures, options, and swaps, to manage its exposure to market risks from its energy assets and energy supply portfolios in accordance with limits and approvals established in its risk management and credit policies.

Integrys Energy Services' long-term energy asset strategy is to invest in distributed renewable projects. Consistent with this strategy, Integrys Energy Services entered into a definitive agreement in October 2012 to sell all of the membership interests of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC, both of which own natural gas-fired generation plants located in the state of New York. This sale is expected to close during the first quarter of 2013. In November 2012, Integrys Energy Services sold all of the membership interests of WPS Westwood Generation, LLC, a waste coal generation plant located in Pennsylvania. Integrys Energy Services is also currently pursuing the sale of Combined Locks Energy Center, a natural gas-fired co-generation plant located in Wisconsin. For more information, see Note 4, “Dispositions.”

Energy Supply

Physical supply obligations are created when Integrys Energy Services executes forward retail customer sales contracts. Integrys Energy Services' electricity supply requirements are primarily met through bilateral electricity purchase agreements with generation companies and other marketers, as well as purchases from regional power pools. Integrys Energy Services does not own any natural gas reserves, so all natural gas supply is procured from producers and other suppliers in the wholesale market. Natural gas is sourced at the customer demand regions, or from the supply region and transported to the customer demand regions under natural gas transportation contracts.

Fuel Supply for Generation Facilities

Integrys Energy Services' natural gas-fired facilities (86.0% of its installed generation portfolio) are subject to market price volatility and are dispatched to produce energy only when it is economical to do so. These facilities were all classified as held for sale at December 31, 2012. See Note 4, "Dispositions," for more information regarding these held for sale facilities. Integrys Energy Services' renewable energy facilities (14.0% of its installed generation portfolio) are all powered by renewable resources such as solar irradiance or landfill gas. There is no market price risk associated with the fuel supply of these facilities; however, production at these facilities can be intermittent due to the availability of the renewable energy resource.

Regulatory Matters

Integrys Energy Services is a FERC-authorized power marketer and has all of the licenses required to conduct business in the states in which it operates.

Other Matters

Customer Segmentation

As of December 31, 2012, Integrys Energy Services' largest retail electric markets included Illinois, New York, New England, Mid-Atlantic, Michigan, and Ohio. In addition, Integrys Energy Services' largest retail natural gas markets included Wisconsin, Illinois, Ohio, Michigan, and Mid-Atlantic. Integrys Energy Services continuously reviews and evaluates the profitability of its operations in each of its markets. Integrys Energy Services continues to concentrate on adding customers in existing markets and placing emphasis on business that provides an appropriate rate of return. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Introduction," for a discussion of the current strategy for Integrys Energy Services.

Integrys Energy Services is not dependent on any one customer segment. Rather, a significant percentage of its retail sales volume is derived from several industries, including educational services; executive, legislative, and general government; paper and allied products; and food and kindred products.

Seasonality

Integrys Energy Services' business, in the aggregate, is somewhat seasonal with certain products selling more heavily in certain seasons than in others. Sales of natural gas generally peak in the winter months, while sales of electricity generally peak in the summer months. The first and fourth quarters, in the aggregate, are typically the most profitable periods. Integrys Energy Services' business can be volatile as a result of market conditions and the related market opportunities available to its customers.

Competition

Integrys Energy Services is a nonregulated retail energy marketer that competes against regulated utilities and other retail energy marketers. Integrys Energy Services competes with other energy providers on the basis of price, reliability, customer service, product offerings, financial strength, consumer convenience, performance, and reputation.

The competitive landscape differs in each regional area and within each targeted customer segment. For residential and small commercial customers, the primary competitive challenges come from the incumbent utility, established national marketers, regional marketers, and affiliated utility marketing companies. The large commercial, institutional, and industrial segments are very competitive in most markets with nearly all natural gas customers having already switched away from utilities to an alternative energy provider. National affiliated marketers, energy producers, and other independent retail energy companies compete for customers in this segment.

The local utilities generally have the advantage of long-standing relationships with their customers, and they have longer operating histories, greater financial and other resources, and greater name recognition in their markets compared to Integrys Energy Services. In addition, local utilities have been subject to many years of regulatory oversight and, thus, have a significant amount of experience regarding the policy preferences of their regulators. Local utilities may seek to decrease their tariff retail rates to limit or preclude opportunities for competitive energy suppliers and may seek to establish rates, terms, and conditions to the disadvantage of competitive energy suppliers.

The retail electric and natural gas markets in which Integrys Energy Services operates continue to evolve. Sustained low commodity prices, capital costs, and market volatility have lowered the barrier to entry into the retail marketing segment of the industry. Coupled with growing market opportunities, this has resulted in increased competition, leading to downward pressure on per-unit margins. However, Integrys Energy Services has been able to take advantage of the continued growth opportunities in certain markets by increasing volumes contracted for future delivery. Integrys Energy Services' electric and natural gas volumes for future delivery have grown by approximately 50% and 23%, respectively, when comparing the future estimated contracted volumes at December 31, 2012 to December 31, 2011.

Working Capital

The working capital needs of Integrys Energy Services vary significantly over time due to volatility in commodity prices and related margin calls, and levels of natural gas storage inventories. Integrys Energy Services' working capital needs are met by cash generated from operations, equity infusions, and short-term debt. As of December 31, 2012, Integrys Energy Services had the ability to borrow up to $665.0 million through an intercompany credit facility with us. As of December 31, 2012, we had provided total parental guarantees of $536.4 million on behalf of Integrys Energy Services, which includes guarantees for the current retail business as well as residual guarantees related to exited businesses. Our exposure under these guarantees related to open transactions at December 31, 2012, was $236.7 million.

E. ELECTRIC TRANSMISSION INVESTMENT

The electric transmission investment segment consists of our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Wisconsin, Michigan, Minnesota, and Illinois. ATC began operations in 2001. See Note 8, "Equity Method Investments," for more information about ATC.

F. HOLDING COMPANY AND OTHER SEGMENT

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. The compressed natural gas operations of ITF are included in this segment as of September 1, 2011, the date on which we acquired Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle). See Note 3, "Acquisitions," for more information about the acquisition of Trillium and Pinnacle.

G. ENVIRONMENTAL MATTERS

For information on our environmental matters, see Note 15, "Commitments and Contingencies."

H. CAPITAL REQUIREMENTS

For information on our capital requirements, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

I. EMPLOYEES

At December 31, 2012, our consolidated subsidiaries had the following full-time employees:

	Total Number of Employees	Percentage of Employees Covered by Collective Bargaining Agreements	
WPS	1,283	70	%
IBS	1,254	—	%
PGL	1,183	74	%
Integrys Energy Services	267	—	%
MERC	214	20	%
NSG	161	78	%
MGU	153	70	%
UPPCO	114	81	%
ITF	88	—	%
Total	4,717	45	%

Our subsidiaries have collective bargaining agreements with various unions which are summarized in the table below.

Union	Subsidiary	Contract Expiration Date	
Local 420 of the International Union of Operating Engineers	WPS	October 13, 2012	*
Local 18007 of the Utility Workers Union of America	PGL	April 30, 2013	
Local 31 of the International Brotherhood of Electrical Workers, AFL CIO	MERC	May 31, 2013	
Local 2285 of the International Brotherhood of Electrical Workers, AFL CIO	NSG	June 30, 2013	
Local 510 of the International Brotherhood of Electrical Workers, AFL CIO	UPPCO	April 12, 2014	
Local 12295 of the United Steelworkers of America, AFL CIO CLC	MGU	January 15, 2015	
Local 417 of the Utility Workers Union of America, AFL CIO	MGU	February 15, 2016	

* A new collective bargaining agreement is currently being negotiated.

J. EXECUTIVE OFFICERS OF INTEGRYS ENERGY GROUP

Name and Age [1]		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	59	Chairman, President and Chief Executive Officer	04-01-10
		President and Chief Executive Officer	01-01-09
		President and Chief Executive Officer of WPS	05-31-08
		President of WPS	02-21-07
Lawrence T. Borgard	51	President and Chief Operating Officer – Utilities	04-05-09
		President and Chief Operating Officer – Integrys Gas Group [2]	02-21-07
Phillip M. Mikulsky	64	Executive Vice President – Corporate Initiatives and Chief Security Officer	01-01-13
		Executive Vice President – Business Performance and Shared Services	12-26-10
		Executive Vice President – Corporate Development and Shared Services	09-21-08
		Executive Vice President and Chief Development Officer	02-21-07
Mark A. Radtke	51	Executive Vice President – Shared Services and Chief Strategy Officer	01-01-13
		Executive Vice President and Chief Strategy Officer	12-26-10
		Chief Executive Officer – Integrys Energy Services	01-10-10
		President and Chief Executive Officer – Integrys Energy Services	06-01-08
		President – Integrys Energy Services (previously named WPS Energy Services, Inc.)	10-17-99
Joseph P. O'Leary	58	Senior Vice President	01-01-13
		Senior Vice President and Chief Financial Officer	06-04-01
James F. Schott	55	Vice President and Chief Financial Officer	01-01-13
		Vice President – External Affairs	03-22-10
		Vice President – Regulatory Affairs	07-18-04
Linda M. Kallas	53	Vice President and Corporate Controller	09-01-12
		Vice President of Finance and Accounting Services	06-06-07
William J. Guc	43	Vice President and Treasurer	12-01-10
		Vice President – Finance and Accounting and Controller – Integrys Energy Services	03-07-10
		Vice President and Controller – Integrys Energy Services	09-21-08
		Controller – Integrys Energy Services (previously named WPS Energy Services)	02-21-05
William D. Laakso	50	Vice President – Human Resources and Corporate Communications	01-01-13
		Vice President – Human Resources	09-21-08
		Interim Vice President – Human Resources – IBS	05-15-08
		Director – Workforce and Organizational Development – WPS	08-12-07
Jodi J. Caro [3]	47	Vice President, General Counsel and Secretary	11-09-12

		Vice President, General Counsel and Assistant Secretary	02-19-12
		Vice President of Legal Services	01-07-08
		Owner, Jodi J. Caro, LLC	11-01-06
Daniel J. Verbanac	49	President – Integrys Energy Services	01-01-10
		Chief Operating Officer – Integrys Energy Services (previously named WPS Energy Services)	02-15-04

(1) Officers and their ages are as of January 1, 2013. None of the executives listed above are related by blood, marriage, or adoption to any of our other officers listed or to any of our directors. Each officer holds office until his or her successor has been duly elected and qualified, or until his or her death, resignation, disqualification, or removal.

(2) The Integrys Gas Group included MGU, MERC, NSG, and PGL.

(3) Prior to joining Integrys Energy Group, Jodi J. Caro owned and operated her own law practice, Jodi J. Caro, LLC, which provided general counsel and corporate transactional services to clients nationwide.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors, as well as the other information included or incorporated by reference in this Annual Report on Form 10-K, when making an investment decision.

We are subject to government regulation, which may have a negative impact on our businesses, financial position, and results of operations.

We are subject to comprehensive regulation by several federal and state regulatory agencies and local governmental bodies. This regulation significantly influences our operating environment and may affect our ability to recover costs from customers of our regulated operations. Many aspects of our operations are regulated, including, but not limited to, construction and operation of facilities, conditions of service, the issuance of securities, and the rates that we can charge customers. We are required to have numerous permits, approvals, and certificates from these agencies to operate our business. Failure to comply with any applicable rules or regulations may lead to penalties or customer refunds, which could have a material adverse impact on our financial results.

Existing statutes and regulations may be revised or reinterpreted by federal and state regulatory agencies, or these agencies may adopt new laws and regulations that apply to us. We are unable to predict the impact on our business and operating results of any such actions by these agencies. However, changes in regulations or the imposition of additional regulations may require us to incur additional expenses or change business operations, which may have an adverse impact on results of operations.

The rates, including adjustments determined under riders, that our regulated utilities are allowed to charge for retail and wholesale services are the most important factors influencing our business, financial position, results of operations, and liquidity. Rate regulation is premised on providing an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, there is no assurance that regulatory commissions will consider all the costs of our regulated utilities to have been prudently incurred. In addition, the regulatory process will not always result in rates that will produce full recovery of such costs or provide for a reasonable return on equity. Certain expense and revenue items are deferred as regulatory assets and liabilities for future recovery or refund to customers, as authorized by regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for prudence and reasonableness. If recovery of costs is not approved or is no longer deemed probable, regulatory assets would be recognized in current period expense and could have a material adverse impact on our financial results.

We are subject to environmental laws and regulations, compliance with which could be difficult and costly.

We are subject to numerous federal and state environmental laws and regulations that affect many aspects of our operations, including future operations. These laws and regulations relate to air emissions, water quality, wastewater discharges, and the generation, transport, and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections, and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, install pollution control equipment or environmental monitoring equipment at our facilities, incur fees for emissions and permits, and incur expenditures for cleanup costs, damages arising from contaminated properties, and monitoring obligations. In addition, there is uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Compliance with current and future environmental laws and regulations may result in increased capital, operating, and other costs. Noncompliance could result in fines, penalties, and injunctive measures affecting our facilities.

Existing environmental laws or regulations may also be revised and/or new laws or regulations seeking to protect the environment may be adopted or become applicable to us. These laws and regulations include, but are not limited to, regulation regarding mercury, sulfur dioxide, and nitrogen oxide emissions, and the management of coal combustion byproducts, including fly ash. The steps we could be required to take to ensure that our facilities are in compliance with any such laws and regulations could be prohibitively expensive. As a result, certain coal-fired electric generating facilities may become uneconomical to run and could result in early retirement of some of our units or may force us to convert the units to an alternative type of fuel. Costs associated with these potential actions could affect our results of operations and financial condition.

Our natural gas utility subsidiaries are accruing liabilities and deferring costs (recorded as regulatory assets) incurred in connection with their former manufactured gas plant sites. These costs include all recoverable costs incurred to date, management's best estimates of future costs for investigation and remediation, and legal expenses, and are net of amounts recovered by or that may be recovered from insurance or other entities. The ultimate costs to remediate these sites could also vary from the amounts currently accrued.

Citizen groups that feel environmental regulations are not being sufficiently enforced by environmental regulatory agencies may also bring citizen enforcement actions against us. Such actions could seek penalties, injunctive relief, and costs of litigation. There is also a risk that private citizens may bring lawsuits to recover environmental damages they believe they have incurred.

We may incur significant costs if laws or regulations are adopted to address climate change.

Political interest in climate change and the effects of greenhouse gas emissions, most notably carbon dioxide, are a concern for the energy industry. Although no legislation is currently pending that would affect us, state or federal legislation could be passed in the future to regulate greenhouse gas emissions. In addition, the EPA began regulating greenhouse gas emissions under the Clean Air Act (CAA) by applying the Best Available Control Technology (BACT) requirements, which are associated with the New Source Review Program. These requirements apply to new and modified larger greenhouse gas emitters. The EPA has issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units, but the EPA has delayed proposing performance standards for existing units. Until legislation is passed at the federal or state level or the EPA adopts final rules for electric utility steam generating units, it remains unclear as to (1) which industry sectors will be impacted, (2) when compliance will be required, (3) the magnitude of the greenhouse gas emissions reductions that will be required, and (4) the costs and opportunities associated with compliance.

It is possible that future carbon regulation will increase the cost of electricity produced at fossil fuel-fired generation units. Future regulation may also affect the capital expenditures we would make at our generation units, including costs to further limit the greenhouse gas emissions from our operations through carbon capture and storage technology. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could also affect the availability or cost of fossil fuels. Future legislation designed to reduce greenhouse gas emissions could make some generating units uneconomical to maintain or operate and could impact future results of operations, cash flows, and financial condition if such costs are not recoverable through regulated rates.

Our natural gas delivery systems may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair of natural gas delivery systems. Fugitive gas typically vents to the atmosphere and consists primarily of methane, a greenhouse gas. Carbon dioxide is also a byproduct of natural gas consumption. As a result, future legislation to regulate greenhouse gas emissions could increase the price of natural gas, restrict the use of natural gas, adversely affect our ability to operate our natural gas facilities, and/or reduce natural gas demand, which could have a material adverse impact on our results of operations and financial condition.

Our operations are subject to various conditions which can result in fluctuations in the number of customers and their usage.

Our operations are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- Fluctuations in general economic conditions and growth in the service areas in which we operate;
- Weather conditions;
- The amount of energy available from current or new competitors; and
- Our customers' continued focus on energy efficiency.

Our operations are subject to risks arising from the reliability of our electric generation, transmission and distribution facilities, natural gas infrastructure facilities and other facilities, as well as the reliability of third-party transmission providers.

The operation of electric generation and natural gas and electric distribution facilities involves many risks, including the risk of potential breakdown or failure of equipment or processes, which may occur due to storms, natural disasters, or other catastrophic events. Other risks include aging infrastructure, fuel supply or transportation disruptions, accidents, employee labor disputes, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, and performance below expected levels. Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by unexpected or uncontrollable events occurring on the systems of these third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operating and maintenance costs, purchased power costs, and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems may occur and are an inherent risk of our business. Unplanned outages may reduce our revenues or may require us to incur significant costs by forcing us to operate our higher cost electric generators or obtain replacement power from third parties in the open market to satisfy our power sales obligations. Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of the lost revenues or increased expenses.

New and pending environmental regulations may force many generation facility owners in the Midwest, including our electric utilities, to retire a significant number of older coal-fired generation facilities, resulting in a potential reduction in the region's capacity reserve margin to below acceptable risk levels. This could also impair the reliability of the Midwest portion of the grid, especially during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

We are obligated to provide safe and reliable service to customers within our service territories. Meeting this commitment requires significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards could adversely affect our operating results through the imposition of penalties and fines or other adverse regulatory outcomes.

Our operations are subject to risks beyond our control, including but not limited to, cyber security attacks, terrorist attacks, acts of war, or unauthorized access to personally identifiable information.

Any future terrorist attack, cyber security attack, and/or act of war affecting our facilities and operations could have an adverse impact on our results of operations, financial condition, and cash flows. The energy industry uses sophisticated information technology systems and network infrastructure, which control an interconnected system of generation, distribution, and transmission systems with other third parties. A cyber security attack may occur despite our security measures or those that we require our vendors to take, including compliance with reliability standards and critical infrastructure protection standards. Cyber security attacks, including those targeting information systems and electronic control systems used at generating facilities and electric and natural gas transmission, distribution, and storage systems, could severely disrupt our operations and result in loss of service to customers. The risk of such attacks may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our business requires the collection and retention of personally identifiable information of our customers, shareholders, and employees, who expect that we will adequately protect such information. A significant theft, loss, or fraudulent use of personally identifiable information may cause our business reputation to be adversely impacted, may lead to potentially large costs to notify and protect the impacted persons, and/or may cause us to become subject to legal claims, fines, or penalties, any of which could adversely impact our results of operations.

The costs of repairing damage to our facilities, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Counterparties and customers may not meet their obligations.

We are exposed to the risk that counterparties to various arrangements who owe us money, electricity, natural gas, coal, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to replace the underlying commitment at then-current market prices or we may be unable to meet all of our customers' natural gas and electric requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, or our results of operations, financial position, or liquidity could otherwise be adversely affected.

Some of our customers are experiencing, or may experience, financial problems that could have a significant impact on their creditworthiness. We cannot provide assurance that financially distressed customers will not default on their obligations to us and that such defaults will not have a material adverse impact on our business, financial position, results of operations, or cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, could adversely impact our receivable collections or increase our bad debt allowances for these customers, which could adversely affect our operating results. In addition, such events might force customers to reduce their future use of our products and services, which could have a material adverse impact on our results of operations and financial condition.

Any change in our ability to sell electricity generated from our facilities at market-based rates may impact earnings.

The FERC has authorized certain of our subsidiaries to sell generation from their facilities at market prices. The FERC retains the authority to modify or withdraw this market-based rate authority. If the FERC determines that the market is not workably competitive, that we or our subsidiaries possess market power, that we are not charging just and reasonable rates, or that we have not complied with the rules required in order to maintain market-based rates, the FERC may require our subsidiaries to sell power at a price based upon the costs incurred in producing the power. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates we may receive.

Poor investment performance of retirement plan investments and other factors impacting retirement plan costs could unfavorably impact our liquidity and results of operations.

We have employee benefit plans that cover substantially all of our employees and retirees. Our cost of providing these benefit plans varies depending upon actual plan experience and assumptions concerning the future. These assumptions include earnings on and/or valuations of plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and required or voluntary contributions to the plans. Depending on the investment performance over time and other factors impacting our costs, we could be required to make larger contributions in the future to fund these plans. These additional funding obligations could have a material adverse impact on our cash flows, financial condition, and/or results of operations. Changes made to the plans may also impact current and future pension and other postretirement benefit costs.

As a holding company, we rely on the earnings of our subsidiaries to meet our financial obligations.

We are a holding company, and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our ability to meet our financial obligations and pay dividends on our common stock is dependent upon the ability of our subsidiaries to make payments to us, whether through dividends or otherwise. Our subsidiaries are separate legal entities that have no obligation to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to make payments to us depends on their earnings, cash flows, capital requirements, general financial condition, and regulatory limitations. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions, which may include requirements to maintain levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

We may not be able to use tax credit and/or net operating loss carryforwards.

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits and net operating loss carryforwards available under the applicable tax codes. We have not fully used these tax credits and net operating loss carryforwards in our previous tax filings, and we may not be able to fully use the tax credits and net operating losses available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit the use of such credits and losses. In addition, any future disallowance of some or all of those tax credits or net operating loss carryforwards as a result of legislative change or adverse determination by one of the applicable taxing jurisdictions could materially affect our tax obligations and financial results.

Adverse capital and credit market conditions could negatively affect our ability to meet liquidity needs, access capital, and/or grow or sustain our current business. Cost of capital and disruptions, uncertainty, and/or volatility in the financial markets could adversely impact our results of operations and financial condition, as well as exert downward pressure on our stock price.

Having access to the credit and capital markets, at a reasonable cost, is necessary for us to fund our operations and capital requirements. The capital and credit markets provide us with liquidity to operate and grow our businesses that is not otherwise provided from operating cash flows and also supports our ability to provide credit support for our subsidiaries. Disruptions, uncertainty, and/or volatility in those markets could increase our cost of capital or limit the availability of capital. If we or our subsidiaries are unable to access the credit and capital markets on terms that are reasonable, we may have to delay raising capital, issue shorter-term securities, and/or bear an increased cost of capital. This, in turn, could impact our ability to grow or sustain our current businesses, cause a reduction in earnings, result in a credit rating downgrade, and/or limit our ability to sustain our current common stock dividend level.

A reduction in our or our subsidiaries' credit ratings could materially and adversely affect our business, financial position, results of operations, and liquidity.

We cannot be sure that any of our or our subsidiaries' credit ratings will not be lowered by a rating agency if, in the rating agency’s judgment, circumstances in the future so warrant. Any downgrade could:

- Require the payment of higher interest rates in future financings and possibly reduce the potential pool of creditors;
- Increase borrowing costs under certain existing credit facilities;
- Limit access to the commercial paper market;
- Limit the availability of adequate credit support for our subsidiaries’ operations; and
- Require provision of additional credit assurance, including cash margin calls, to contract counterparties.

Fluctuating commodity prices may impact energy margins and result in changes to liquidity requirements.

The margins and liquidity requirements of our businesses are impacted by changes in the forward and current market prices of natural gas, coal, electricity, renewable energy credits, and ancillary services. Changes in price could result in:

- Higher working capital costs, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;

- Increased liquidity requirements due to potential counterparty margin calls related to the use of derivative instruments to manage commodity price and volume exposure;
- Reduced profitability to the extent that reduced margins, increased bad debt, and interest expenses are not recovered through rates;
- Higher rates charged to our customers, which could impact the company's competitive position;
- Reduced demand for energy, which could impact margins and operating expenses; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

We have recorded goodwill and other intangibles that could become impaired.

To the extent the value of goodwill or other intangibles becomes impaired, we have had to, and in the future, may also be required to, incur material noncash charges relating to such impairments. These impairment charges could have a material impact on our financial results.

We are subject to the Wisconsin Public Utility Holding Act, which may limit merger and acquisition opportunities that could benefit our shareholders.

The Wisconsin Public Utility Holding Company Law limits our ability to invest in nonutility related businesses and may make it more difficult for others to obtain control of us. This law mandates that the PSCW must first determine that the acquisition is in the best interests of utility customers, investors, and the public. Those interests may, to some extent, be mutually exclusive. This provision and other requirements of the Wisconsin Public

Utility Holding Company Act may delay, or reduce the likelihood of, a sale or change of control thus reducing the likelihood that shareholders will receive a takeover premium for their shares.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2012:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)	
Steam	Columbia Units 1 and 2	Portage, Wisconsin	Coal	356.8	(2)
	Edgewater Unit 4	Sheboygan, Wisconsin	Coal	100.9	(2)
	Pulliam (4 units)	Green Bay, Wisconsin	Coal	325.0	
	Weston Units 1, 2, and 3	Marathon County, Wisconsin	Coal	458.9	
	Weston Unit 4	Marathon County, Wisconsin	Coal	375.2	(2)
Total Steam				1,616.8	
Combustion Turbine and Diesel	De Pere Energy Center	De Pere, Wisconsin	Natural Gas	163.7	
	Gladstone	Gladstone, Michigan	Oil	15.6	
	Juneau #31	Adams County, Wisconsin	Distillate Fuel Oil	6.1	(2)
	Portage	Houghton, Michigan	Oil	16.7	
	Pulliam #31	Green Bay, Wisconsin	Natural Gas	85.0	
	West Marinette #31	Marinette, Wisconsin	Natural Gas	38.6	
	West Marinette #32	Marinette, Wisconsin	Natural Gas	38.6	
	West Marinette #33	Marinette, Wisconsin	Natural Gas	76.9	
	Weston #31	Marathon County, Wisconsin	Natural Gas	15.4	
	Weston #32	Marathon County, Wisconsin	Natural Gas	46.3	
Total Combustion Turbine and Diesel				502.9	
Hydroelectric	Various	Michigan	Hydro	16.9	
	Various	Wisconsin	Hydro	66.5	(3)

Total Hydroelectric				83.4
Wind	Lincoln	Wisconsin	Wind	1.0
	Crane Creek	Iowa	Wind	18.8
Total Wind				19.8
Total System				2,222.9

(1) Based on capacity ratings for July 2013, which can differ from nameplate capacity, especially on wind projects. The summer period is the most relevant for capacity planning purposes at our electric segment as a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(2) These facilities are jointly owned by WPS and various other utilities. The capacity indicated for each of these units is equal to WPS's portion of total plant capacity based on its percent of ownership.

- Wisconsin Power and Light Company operates the Columbia and Edgewater units, and WPS holds a 31.8% ownership interest in these facilities.
- WPS operates the Weston 4 facility and holds a 70% ownership in this facility, while Dairyland Power Cooperative holds the remaining 30% interest.
- WRPC owns and operates the Juneau unit. WPS holds a 50% ownership interest in WRPC.

(3) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50% ownership interest in WRPC; however, WPS is entitled to 66.6% of total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 11.6 megawatts, and WPS's share of capacity for Petenwell is 13.4 megawatts.

In September 2012, WPS entered into an agreement to purchase the Fox Energy Center, a 593-megawatt combined-cycle electric generating natural gas facility located in Wisconsin. The transaction is expected to close by the end of March 2013.

As of December 31, 2012, our electric utilities owned approximately 25,000 miles of electric distribution lines located in Michigan and Wisconsin and 181 distribution substations.

Natural Gas Facilities

At December 31, 2012, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,200 miles of natural gas distribution mains,
- Approximately 1,000 miles of natural gas transmission mains,
- Approximately 300 natural gas distribution and transmission gate stations,
- Approximately 1.3 million natural gas lateral services,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.2 billion-cubic-foot underground natural gas storage reservoir located in central Illinois,* and
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois.*

* PGL owns and operates this reservoir and liquefied natural gas plant in central Illinois (Manlove Field). PGL also owns a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. The underground storage reservoir also serves NSG under a contractual arrangement. PGL uses its natural gas storage and pipeline supply assets as a natural gas hub in the Chicago area.

General

Substantially all of our utility plant at WPS, PGL, and NSG is subject to first mortgage liens.

B. INTEGRYS ENERGY SERVICES

The following table summarizes information on the energy asset facilities owned by Integrys Energy Services as of December 31, 2012:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) [1]	
Combined Cycle	Beaver Falls	Beaver Falls, New York	Gas/Oil	78.5	[4]
	Combined Locks	Combined Locks, Wisconsin	Gas	45.5	[2]
	Syracuse	Syracuse, New York	Gas/Oil	84.1	[4]
Total Combined Cycle				208.1	
Reciprocating Engine	Winnebago	Rockford, Illinois	Landfill Gas	6.1	
Solar	Various	Various States	Solar Irradiance	27.9	[3]
Total Energy Assets				242.1	
				Length of Pipeline (Miles)	
Landfill Gas Transportation	LGS	Brazoria County, Texas	N/A	33 miles	

(1) Based on summer rated capacity.

(2) Combined Locks has an additional five megawatts of capacity available at this facility through the lease of a steam turbine. Integrys Energy Services is currently pursuing the sale of Combined Locks Energy Center. For more information, see Note 4, "Dispositions."

(3) The solar facilities consist of small distributed solar projects ranging from 0.1 to 2.3 megawatts in size. A portion of the solar facilities are wholly owned by subsidiaries of Integrys Energy Services and others are owned by INDU Solar Holdings, LLC, which is a jointly owned subsidiary of Integrys Energy Services and Duke Energy Generation Services. Of the capacity listed, 7.4 megawatts is Integrys Energy Services' portion of total solar capacity based on their 50% ownership in INDU Solar Holdings, LLC.

(4) Integrys Energy Services entered into a definitive agreement in 2012 to sell all of the membership interests of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC. This sale is expected to close during the first quarter of 2013. For more information, see Note 4, "Dispositions."

C. HOLDING COMPANY AND OTHER

The following table summarizes information on the compressed natural gas fueling stations owned by ITF as of December 31, 2012:

Type	Name	Location	Number of Locations *
Compressed Natural Gas (CNG)	Various	Various States	16

* The CNG fueling stations consist of 13 stations that are wholly owned and operated by Trillium and three stations that are owned by Trillium HD, which is a jointly owned subsidiary of ITF and Paper Transport, Inc. ITF operates the stations, and holds a 50% ownership in Trillium HD.

ITEM 3. LEGAL PROCEEDINGS

For information on material legal proceedings and matters related to us and our subsidiaries, see Note 15, "Commitments and Contingencies."

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock and Dividend Data

Our common stock is traded on the New York Stock Exchange under the ticker symbol "TEG." The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company, LLC, 6201 15th Avenue, Brooklyn, NY 11219. The quarterly high and low sales prices for our common stock and the cash dividends per share declared for each quarter during the past two years were as follows:

	2012			2011		
Quarter	High	Low	Dividends	High	Low	Dividends
First	$54.88	$50.80	$0.68	$51.03	$47.51	$0.68
Second	57.55	50.89	0.68	54.02	49.10	0.68
Third	61.92	51.79	0.68	52.79	42.76	0.68
Fourth	55.83	51.14	0.68	54.61	45.75	0.68

As of the close of business on February 20, 2013, we had 28,208 holders of record of our common stock.

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note 19, "Common Equity."

Equity Compensation Plans

See Item 11, "Executive Compensation," for information regarding equity securities authorized for issuance under our equity compensation plans.

Issuer Purchases of Equity Securities

The following table provides a summary of common stock purchases for the three months ended December 31, 2012:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
10/01/2012 - 10/31/2012 *	28,977	$55.06	—	—
11/01/2012 - 11/30/2012 *	12,682	53.05	—	—
12/01/2012 - 12/31/2012 *	71,078	53.82	—	—
Total	112,737	$54.05	—	—

* Represents shares purchased in the open market by American Stock Transfer & Trust Company to satisfy obligations under various equity compensation plans and to provide shares to participants in the Stock Investment Plan.

18

ITEM 6. SELECTED FINANCIAL DATA

INTEGRYS ENERGY GROUP, INC.
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 (Millions, except per share amounts, stock price, return on average equity, and number of shareholders and employees)	2012	2011	2010	2009	2008
Total revenues	$4,212.4	$4,685.9	$5,169.8	$7,464.7	$14,009.0
Net income (loss) from continuing operations	294.0	230.0	245.2	(74.8)	112.4
Net income (loss) attributed to common shareholders	281.4	227.4	220.9	(69.6)	116.5
Total assets	10,327.4	9,983.2	9,816.8	11,844.6	14,268.7
Preferred stock of subsidiary	51.1	51.1	51.1	51.1	51.1
Long-term debt (excluding current portion)	1,931.7	1,845.0	2,134.6	2,367.7	2,258.7
Average shares of common stock					
Basic	78.6	78.6	77.5	76.8	76.7
Diluted	79.3	79.1	78.0	76.8	77.0
Earnings (loss) per common share (basic)					
Net income (loss) from continuing operations	$3.70	$2.89	$3.13	$(1.01)	$1.43
Earnings (loss) per common share (basic)	3.58	2.89	2.85	(0.91)	1.52
Earnings (loss) per common share (diluted)					
Net income (loss) from continuing operations	3.67	2.87	3.11	(1.01)	1.42
Earnings (loss) per common share (diluted)	3.55	2.87	2.83	(0.91)	1.51
Dividends per common share declared	2.72	2.72	2.72	2.72	2.68
Stock price at year-end	$52.22	$54.18	$48.51	$41.99	$42.98
Book value per share	$38.84	$38.01	$37.57	$37.51	$40.66
Return on average equity	9.4 %	7.7 %	7.7 %	(2.4)%	3.6 %
Number of common stock shareholders	28,425	28,993	30,352	32,755	34,016
Number of employees	4,717	4,619	4,612	5,025	5,191

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

We are a diversified energy holding company with regulated natural gas and electric 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).

Strategic Overview

Our goal is to create long-term value for shareholders and customers through growth in our core regulated businesses. We also have a nonregulated energy services business segment that is focused on growth within a controlled risk profile.

The essential components of our business strategy are:

Maintaining and Growing a Strong Regulated Utility Base – A strong regulated utility base is essential to maintaining a strong balance sheet, predictable cash flows, the desired risk profile, attractive dividends, and quality credit ratings. We believe the following projects have helped, or will help, maintain and grow our regulated utility base and meet our customers' needs:

- WPS's pending purchase of the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility located in Wisconsin, in 2013
- The System Modernization and Reliability Project that WPS plans to begin in 2014 to underground certain electric distribution lines in northern Wisconsin
- WPS's continued investment in environmental projects to improve air quality and meet or exceed the requirements set by environmental regulators
- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.3 billion of transmission assets at December 31, 2012. ATC plans to invest approximately $3.9 billion to $4.8 billion during the next ten years. Although ATC's equity requirements to fund its capital investments will primarily be met by earnings reinvestment, we plan to continue to fund our share of the equity portion of future ATC growth as necessary
- An accelerated annual investment in natural gas distribution facilities (primarily replacement of cast iron mains) at PGL.

For more detailed information on our capital expenditure program, see "Liquidity and Capital Resources, Capital Requirements."

Providing Safe, Reliable, Competitively Priced, and Environmentally Sound Energy and Related Services – Our mission is to provide customers with the best value in energy and related services. We strive to effectively operate a mixed portfolio of generation assets and prudently invest in new generation and distribution assets, while maintaining or exceeding environmental standards. This allows us to provide a safe, reliable, value-priced service to our customers. Our recent entry into the compressed natural gas fueling marketplace, while not currently significant, is complementary to our existing businesses and is consistent with our mission.

Operating a Nonregulated Energy Services Business Segment with a Controlled Risk and Capital Profile – Through our nonregulated Integrys Energy Services subsidiary, we provide retail natural gas and electric products to end-use customers in the northeast quadrant of the United States. This subsidiary is focused on operating within select retail electric and natural gas markets in our current market footprint where we have experience and believe we will have the most success growing our recurring retail customer based business. In addition, Integrys Energy Services continues to develop, acquire, own, and operate renewable energy projects, primarily distributed solar generation, in the United States. This strategy is intended to result in dependable cash and earnings contributions with a controlled risk and capital profile.

Integrating Resources to Provide Operational Excellence – We are committed to integrating resources of all our businesses, while meeting all applicable legal and regulatory requirements. This will provide the best value to customers and shareholders by leveraging the individual capabilities and expertise of each business and lowering costs. "Operational Excellence" initiatives have been implemented to reduce costs and encourage top performance in the areas of project management, process improvement, contract administration, and compliance.

Placing Strong Emphasis on Asset and Risk Management – Our asset management strategy calls for the continuous assessment of existing assets, the acquisition of assets, and contractual commitments to obtain resources that complement our existing business and strategy. The goal is to provide the most efficient use of resources while maximizing return and maintaining an acceptable risk profile. This strategy focuses on acquiring assets consistent with strategic plans and disposing of assets, including property, plant, and equipment and entire business units, that are no longer strategic to ongoing operations, are not performing as intended, or have an unacceptable risk profile. We maintain a portfolio approach to risk and earnings.

Our risk management strategy includes the management of market, credit, liquidity, and operational risks through the normal course of business. Forward purchases and sales of electric capacity, energy, natural gas, and other commodities and the use of derivative financial instruments, including commodity swaps and options, provide tools to reduce the risk associated with price movement in a volatile energy market. Each business unit manages the risk profile related to these instruments consistent with our risk management policies, which are approved by the Board of Directors. The Corporate Risk Management Group, which reports through the Chief Financial Officer, provides corporate oversight.

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Year Ended December 31 2012	2011	2010	Change in 2012 Over 2011	Change in 2011 Over 2010
Natural gas utility operations	$93.4	$103.3	$84.0	(9.6)%	23.0%
Electric utility operations	107.9	100.5	109.8	7.4%	(8.5)%
Electric transmission investment	52.4	47.8	46.2	9.6%	3.5%
Integrys Energy Services operations	41.1	(6.1)	3.3	N/A	N/A
Holding company and other operations	(13.4)	(18.1)	(22.4)	(26.0)%	(19.2)%
Net income attributed to common shareholders	$281.4	$227.4	$220.9	23.7%	2.9%
Basic earnings per share	$3.58	$2.89	$2.85	23.9%	1.4%
Diluted earnings per share	$3.55	$2.87	$2.83	23.7%	1.4%
Average shares of common stock					
Basic	78.6	78.6	77.5	—%	1.4%
Diluted	79.3	79.1	78.0	0.3%	1.4%

2012 Compared with 2011

Our earnings for 2012 were $281.4 million, compared with $227.4 million for 2011. The $54.0 million increase in earnings was driven by:

- A $60.1 million after-tax increase in Integrys Energy Services' margins from noncash derivative and inventory fair value adjustments.

- A $33.7 million after-tax positive impact related to rate orders at the natural gas utilities, excluding items directly offset in operating expenses.

These increases were partially offset by:

- A $26.2 million after-tax decrease in natural gas utility margins due to lower sales volumes driven by warmer weather, net of decoupling.

- A $12.5 million decrease in income from discontinued operations at Integrys Energy Services. See Note 4, "Dispositions," for more information.

2011 Compared with 2010

Our earnings for 2011 were $227.4 million, compared with $220.9 million for 2010. The $6.5 million increase in earnings was driven by:

-

- A $24.4 million after-tax net decrease in operating expenses across all segments, driven by a decrease in employee benefit costs and lower depreciation and amortization expense.

- A $22.5 million decrease in losses from discontinued operations at Integrys Energy Services, primarily due to the impairment losses recorded in 2010 related to three generation plants. See Note 4, "Dispositions," for more information.

- A $15.4 million after-tax increase in Integrys Energy Services' realized margins.

- The $15.0 million positive year-over-year impact of tax adjustments recorded in 2011 and 2010 in connection with federal health care reform.

These increases were partially offset by:

- A $61.3 million after-tax decrease in Integrys Energy Services' margins from noncash derivative and inventory fair value adjustments.

- An $8.4 million after-tax decrease in electric utility margins, mainly caused by differences in WPS's 2011 electric rate order compared with the previous rate order.

Regulated Natural Gas Utility Segment Operations

(Millions, except degree days)	Year Ended December 31 2012	2011	2010	Change in 2012 Over 2011	Change in 2011 Over 2010
Revenues	$1,672.0	$1,998.0	$2,057.2	(16.3)%	(2.9)%
Purchased natural gas costs	775.0	1,101.4	1,152.0	(29.6)%	(4.4)%
Margins	897.0	896.6	905.2	—%	(1.0)%
Operating and maintenance expense	527.5	523.6	541.9	0.7%	(3.4)%
Depreciation and amortization expense	131.8	126.1	130.9	4.5%	(3.7)%
Taxes other than income taxes	35.6	35.6	34.4	—%	3.5%
Operating income	202.1	211.3	198.0	(4.4)%	6.7%
Miscellaneous income	0.6	2.2	1.6	(72.7)%	37.5%
Interest expense	(47.3)	(48.4)	(49.7)	(2.3)%	(2.6)%
Other expense	(46.7)	(46.2)	(48.1)	1.1%	(4.0)%
Income before taxes	$155.4	$165.1	$149.9	(5.9)%	10.1%
Retail throughput in therms					
Residential	1,324.8	1,541.5	1,496.4	(14.1)%	3.0%
Commercial and industrial	406.0	469.5	455.5	(13.5)%	3.1%
Other	75.3	61.3	53.7	22.8%	14.2%
Total retail throughput in therms	1,806.1	2,072.3	2,005.6	(12.8)%	3.3%
Transport throughput in therms					
Residential	204.0	237.4	224.4	(14.1)%	5.8%
Commercial and industrial	1,557.9	1,559.7	1,504.0	(0.1)%	3.7%
Total transport throughput in therms	1,761.9	1,797.1	1,728.4	(2.0)%	4.0%
Total throughput in therms	3,568.0	3,869.4	3,734.0	(7.8)%	3.6%
Weather					
Average heating degree days	5,601	6,675	6,440	(16.1)%	3.6%

2012 Compared with 2011

Margins

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 20% decrease in the average per-unit cost of natural gas sold during 2012, which had no impact on margins.

Regulated natural gas utility segment margins increased $0.4 million, driven by:

- An approximate $42 million net increase in margins due to rate orders. See Note 25, "Regulatory Environment," for more information.

The rate increases at PGL and NSG, effective January 21, 2012, and other impacts of rate design, had an approximate $48 million positive impact on margins.

A reduction in rates at WPS, effective January 1, 2012, resulted in an approximate $5 million negative impact on margins. The rate decrease was driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions is offset by lower operating expenses.

MERC had an approximate $1 million decrease in margins in 2012 primarily driven by the impact of a rate order from the MPUC finalized in January 2013. A preliminary order was received in July 2012 that adjusted 2011 interim rates in effect since February 1, 2011.

- An approximate $4 million net increase in margins related to certain riders at PGL and NSG. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

PGL and NSG billed approximately $7 million more to customers for energy efficiency programs in 2012.

PGL and NSG refunded approximately $2 million more to customers under bad debt riders in 2012.

PGL and NSG recovered approximately $1 million less for environmental cleanup costs at their former manufactured gas plant sites in 2012. The lower recovery reflects a pass-through to customers in rates of an environmental settlement received by NSG from a potentially responsible party's performance and payment bond. The impact of the settlement was partially offset by an increase in remediation activity at PGL during 2012. See Note 15, "Commitment and Contingencies," for more information about the manufactured gas plant sites.

The above increases in margins were partially offset by an approximate $43 million net decrease in margins, including the impact of decoupling, due to a 7.8% decrease in volumes sold.

- Substantially warmer weather during 2012 drove an approximate $55 million decrease in margins. Heating degree days decreased 16.1%.

- Lower sales volumes excluding the impact of weather resulted in an approximate $6 million decrease in margins. Sales volumes were slightly lower due to lower use per customer.

- Decoupling impacts at certain natural gas utilities drove an approximate $18 million increase in margins. Decoupling does not cover all jurisdictions or customer classes.

Decoupling accruals in 2012 had an approximate $9 million positive impact on the year-over-year variance. Decoupling lessened the negative impact from some of the decreased sales volumes at WPS and MGU through higher future recoveries from customers. This was limited by an $8.0 million decoupling cap that was reached by WPS during the second quarter of 2012. In 2012, reserves were recorded against all decoupling accruals at PGL and NSG after an ICC order declared these amounts may be subject to refund. See Note 25, "Regulatory Environment," for more information.

Decoupling accruals in 2011 had an approximate $9 million positive impact on the year-over-year variance. Decoupling lessened the positive impact in 2011 from some of the higher sales volumes at PGL, NSG, WPS, and MGU through higher future refunds to customers.

Operating Income

Operating income at the regulated natural gas utility segment decreased $9.2 million. This decrease was driven by a $9.6 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $24.6 million increase in natural gas distribution costs, primarily at PGL. The increase was partially due to increased labor costs driven by annual wage increases, as well as additional employees required for compliance work related to inside safety inspections and corrosion review. Additional contractors were also needed for street restoration and pipe maintenance to replace employees that were moved to the AMRP project.

- A $5.7 million increase in depreciation and amortization expense resulting from increased investment in property and equipment, primarily driven by the AMRP.

- An approximate $4 million net increase at PGL and NSG driven by an increase in regulatory liabilities related to energy efficiency programs, partially offset by higher amortization of regulatory liabilities related to bad debt riders and lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites. Margins increased by an equal amount, resulting in no impact on earnings.

These increases were partially offset by:

- A $9.9 million decrease in energy efficiency program expenses related to WPS's participation in the Focus on Energy Program and MERC's conservation improvement program. Costs for both programs are recovered in rates.

- An $8.6 million decrease in bad debt expense, driven by a new cost of gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. The change in the bad debt mechanisms was approved in PGL's and NSG's rate orders, effective January 21, 2012. In those orders, the ICC required that a natural gas cost component of the bad debt mechanism be charged to customers based on actual volumes and natural gas prices. As a result of this component, bad debt expense was primarily impacted by lower natural gas costs in 2012 and, to a lesser extent, by the decrease in sales volumes. However, $6.8 million of the decrease in bad debt expense does not impact earnings as it is offset by lower rates, resulting in lower margins.

- A $2.7 million decrease in workers compensation expense related to both fewer incidents and less severe injuries during 2012, primarily at PGL.

- A $2.4 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.

2011 Compared with 2010

Margins

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 7% decrease in the average per-unit cost of natural gas sold during 2011, which had no impact on margins.

Regulated natural gas utility segment margins decreased $8.6 million and was driven by the approximate $19 million negative year-over-year impact related to certain riders at PGL and NSG. This decrease in margins was offset by an equal decrease in operating expenses, resulting in no impact on earnings. We refunded approximately $13 million more to customers under bad debt riders in 2011. We also recovered approximately $6 million less for environmental cleanup costs at our former manufactured gas plant sites in 2011. See Note 15, "Commitment and Contingencies," for more information on our manufactured gas plant sites.

The decrease in margins was partially offset by:

- An approximate $4 million net increase in margins, including the impact of decoupling, due to a 3.6% increase in volumes sold.

Higher sales volumes excluding the impact of weather resulted in approximately $17 million of additional margins. We attribute this increase to a combination of higher use per customer, higher average customer counts, and improved economic conditions for certain customers.

Colder weather during 2011 drove an approximate $6 million increase in margins. Heating degree days increased 3.6%.

Decoupling impacts at certain natural gas utilities drove an approximate $19 million decrease in margins. Decoupling does not cover all jurisdictions or customer classes.

Decoupling accruals in 2011 had an approximate $9 million negative impact on the year-over-year variance. Decoupling lessened the positive impact in 2011 from some of the increased sales volumes at PGL, NSG, WPS, and MGU through higher future refunds to customers.

Decoupling accruals in 2010 had an approximate $10 million negative impact on the year-over-year variance. Decoupling lessened the negative impact in 2010 from some of the decreased sales volumes at PGL, NSG, WPS, and MGU through higher future recoveries from customers.

- An approximate $4 million net increase in margins due to rate orders. See Note 25, "Regulatory Environment," for more information.

MERC's conservation improvement program (CIP) rate increase, effective November 1, 2010, and its interim natural gas distribution rate increase, effective February 1, 2011, had a combined approximate $13 million positive impact on margin. The CIP margins of approximately $7 million did not impact earnings as they were offset by an increase in operating and maintenance expense.

The rate increases at PGL and NSG, effective January 28, 2010, and other impacts of rate design, had an approximate $7 million net positive impact on margins.

A reduction in rates at WPS, effective January 14, 2011, resulted in an approximate $16 million negative impact on margins.

- An approximate $2 million increase in margins due to a year-over-year positive impact from the 2010 amortization of a regulatory asset at WPS related to energy efficiency legislation implemented in a prior year.

- An approximate $2 million increase in margins due to a rider approved through September 30, 2011 for recovery of AMRP costs at PGL.

See Note 25, "Regulatory Environment," for more information.

Operating Income

Operating income at the regulated natural gas utility segment increased $13.3 million. This increase was primarily driven by a $21.9 million decrease in operating expenses, partially offset by the $8.6 million decrease in margins discussed above.

The decrease in operating expenses primarily related to:

- An approximate $19 million decrease due to higher amortization of regulatory liabilities related to bad debt riders and lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites, all at PGL and NSG. Margins decreased by an equal amount, resulting in no impact on earnings.

- A $4.8 million decrease in depreciation and amortization expense. WPS received approval for lower depreciation rates from the PSCW, effective January 1, 2011. The decrease also reflects the impact of a $2.5 million write-off of certain MGU assets in 2010 based on an order from the MPSC that was subsequently reversed by the Michigan Court of Appeals in January 2013. See Note 25, "Regulatory Environment," for more information.

- A $7.8 million decrease in employee benefits expense, partially driven by lower employee health care costs.

- A $3.6 million decrease in customer accounts expense resulting from lower customer call volumes and a decrease in labor associated with fewer disconnections.

- A $2.6 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.

These decreases were partially offset by:

- A $10.0 million increase in natural gas distribution costs. The increase was partially due to additional labor related to distribution operations activities and additional consulting costs associated with a work asset management system and the AMRP. Transportation costs, building maintenance, meter maintenance projects, and other miscellaneous distribution costs also contributed to the increase.

- A $5.0 million increase in expenses related to energy conservation and efficiency programs. This net increase includes expenses related to the CIP that were recovered through the MERC rate increase discussed in margins above.

Other Expense

Other expense decreased $1.9 million, driven by a decrease in interest expense on long-term debt. PGL refinanced some of its long-term debt at lower interest rates in the second half of 2010. In addition, WPS did not replace certain senior notes that matured in the third quarter of 2011.

Regulated Electric Utility Segment Operations

(Millions, except degree days)	Year Ended December 31 2012	2011	2010	Change in 2012 Over 2011	Change in 2011 Over 2010
Revenues	$1,297.4	$1,307.3	$1,338.9	(0.8)%	(2.4)%
Fuel and purchased power costs	562.1	546.3	563.9	2.9 %	(3.1)%
Margins	735.3	761.0	775.0	(3.4)%	(1.8)%
Operating and maintenance expense	405.6	421.7	416.9	(3.8)%	1.2 %
Depreciation and amortization expense	89.0	88.5	94.7	0.6 %	(6.5)%
Taxes other than income taxes	47.6	47.6	45.6	— %	4.4 %
Operating income	193.1	203.2	217.8	(5.0)%	(6.7)%
Miscellaneous income	2.6	0.8	1.5	225.0 %	(46.7)%
Interest expense	(35.9)	(41.8)	(43.9)	(14.1)%	(4.8)%
Other expense	(33.3)	(41.0)	(42.4)	(18.8)%	(3.3)%
Income before taxes	$159.8	$162.2	$175.4	(1.5)%	(7.5)%
Sales in kilowatt-hours					
Residential	3,106.6	3,135.6	3,114.3	(0.9)%	0.7 %
Commercial and industrial	8,574.5	8,520.9	8,439.6	0.6 %	1.0 %
Wholesale	4,614.7	4,256.8	4,994.7	8.4 %	(14.8)%
Other	38.0	38.4	39.1	(1.0)%	(1.8)%
Total sales in kilowatt-hours	16,333.8	15,951.7	16,587.7	2.4 %	(3.8)%
Weather – WPS:					
Heating degree days	6,356	7,524	7,080	(15.5)%	6.3 %
Cooling degree days	789	603	616	30.8 %	(2.1)%
Weather – UPPCO:					
Heating degree days	7,749	8,676	8,002	(10.7)%	8.4 %
Cooling degree days	335	305	301	9.8 %	1.3 %

2012 Compared with 2011

Margins

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

Regulated electric utility segment margins decreased $25.7 million, driven by:

- An approximate $21 million decrease in margins related to WPS rate case effects. Although the PSCW approved a rate increase effective January 1, 2012, it was driven by anticipated increases in fuel and purchased power costs that did not materialize. Under the fuel rules, we deferred a portion of the difference between the fuel window costs included in rates and the actual fuel window costs. This portion will be refunded to customers.

Excluding the impact from fuel and purchased power costs, the 2012 rate case re-opener resulted in a rate decrease. The rate decrease was primarily driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The approximate $11 million margin impact from the reduction in contributions to the Focus on Energy Program was offset by lower operating expenses due to reduced payments to the program in 2012.

Fuel costs not included in the fuel window were lower relative to the rate case-approved amounts in 2011. This resulted in an approximate $9 million negative year-over-year impact on margins.

- An approximate $6 million decrease in wholesale margins, driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one wholesale large customer and the loss of wholesale customers.

- An approximate $2 million net decrease in margins from retail customers due to variances related to sales volumes. The margin impact from the period-over-period change in sales volumes was partially offset by the impacts from decoupling mechanisms. Although decoupling was implemented to minimize the impact of changes in sales volumes, WPS's decoupling mechanism does not cover all customers or jurisdictions. UPPCO's decoupling mechanism was terminated at the end of 2011.

A 0.9% decrease in sales volumes to residential customers, driven by warmer weather during the heating season, resulted in an approximate $3 million decrease in margins.

Margins increased approximately $1 million due to decoupling mechanisms.

These decreases were partially offset by:

- An approximate $5 million increase in margins due to a retail electric rate increase at UPPCO, effective January 1, 2012.

Operating Income

Operating income at the regulated electric utility segment decreased $10.1 million. The decrease was driven by the $25.7 million decrease in margins discussed above, partially offset by a $15.6 million decrease in operating expenses. The decrease in operating expenses was driven by:

- An $11.3 million decrease in customer assistance expense driven by reduced payments to the Focus on Energy program. These payments are recovered in rates.

- A $2.2 million decrease in bad debt expense, driven by the year-over-year impact of the 2011 write-off of receivables related to the bankruptcy of an UPPCO retail customer and the subsequent recovery of those receivables in the fourth quarter of 2012.

- A $2.2 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.

- A $1.9 million decrease in maintenance expense, mainly due to fewer repairs at UPPCO's hydroelectric facilities in 2012 as well as fewer storms in WPS's service territories in 2012 compared with 2011.

- These decreases were partially offset by a $2.0 million increase in employee benefit related expenses. The increase was primarily due to an increase in postretirement medical expenses as well as the year-over-year change in the fair value of amounts owed to plan participants under deferred compensation plans. Partially offsetting these increases was lower pension expense driven by an increase in contributions, which increased plan assets.

Other Expense

Other expense decreased $7.7 million, driven by the maturity and repayment of $150 million of long-term debt at WPS in August 2011. Also contributing to the decrease in other expense was an increase in AFUDC, primarily related to environmental compliance projects at the Columbia plant.

2011 Compared with 2010

Margins

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric utility margins provide a more meaningful basis for evaluating utility operations than electric operating revenues. To the extent changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in operating revenues. Any significant changes in fuel and purchased power costs that are not recovered from customers are explained in the margin discussion below.

Regulated electric utility segment margins decreased $14.0 million, driven by:

- An approximate $18 million decrease in retail margins due to differences between the 2011 WPS rate order and the previous rate order. Although the 2011 rate order included a lower authorized return on common equity, lower rate base, and other reduced costs, which resulted in lower total revenues and margins, the rate order also projected lower total sales volumes, which led to a rate increase on a per-unit basis. The 2011 rate increase, calculated on a per unit basis, was more than offset by the decoupling mechanism due to changes in the rate order that impact the decoupling calculation. For more details on the WPS 2011 rate order, see Note 25, "Regulatory Environment."

- An approximate $5 million decrease in margins from wholesale customers. The decrease was due to lower sales volumes and lower nonfuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.

These decreases were partially offset by:

- An approximate $6 million increase in margins driven by a retail electric rate increase at UPPCO.
- An approximate $3 million increase in margins due to a year-over-year positive impact from the 2010 amortization of a regulatory asset at WPS related to energy efficiency legislation implemented in a prior year.

Operating Income

Operating income at the regulated electric utility segment decreased $14.6 million, driven by the $14.0 million decrease in margins and a $0.6 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $4.9 million increase in the amortization of various regulatory deferrals. This increase was offset in revenues, resulting in no impact on earnings.
- A $3.6 million increase in customer assistance expense related to payments made to the Focus on Energy program. The program promotes residential and small business energy efficiency and renewable energy products.
- A $2.0 million increase in taxes other than income taxes, driven by increases in gross receipts taxes and property taxes.
- A $1.9 million increase in electric transmission expense.
- A $1.8 million increase in injuries and damages expenses.

These increases were substantially offset by:

- A $7.7 million decrease in employee benefit costs. The decrease was partially due to lower pension expense driven by an increase in contributions, which increased plan assets.
- A $6.2 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 decreased $1.4 million, driven by a decrease in interest expense due to the maturity and repayment of $150 million of long-term debt at WPS in August 2011.

Electric Transmission Investment Segment Operations

	Year Ended December 31			Change in	Change in
(Millions)	2012	2011	2010	2012 Over 2011	2011 Over 2010
Earnings from equity method investments	$85.3	$79.1	$77.6	7.8 %	1.9 %

2012 Compared with 2011

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $6.2 million in 2012. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

2011 Compared with 2010

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $1.5 million in 2011. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

Integrys Energy Services Nonregulated Segment Operations

(Millions, except natural gas sales volumes)	Year Ended December 31 2012	2011	2010	Change in 2012 Over 2011	Change in 2011 Over 2010
Revenues	$1,218.5	$1,373.1	$1,790.3	(11.3)%	(23.3)%
Cost of sales	1,021.4	1,265.3	1,605.9	(19.3)%	(21.2)%
Margins	197.1	107.8	184.4	82.8 %	(41.5)%
Margin Detail					
Realized retail electric margins	91.3	98.5	85.4 [2][4]	(7.3)%	15.3 %
Realized wholesale electric margins	(0.6)[1]	(0.2)[1]	(8.0)[3]	200.0 %	(97.5)%
Realized renewable energy asset margins	15.0	12.2	13.8	23.0 %	(11.6)%
Fair value accounting adjustments	38.0	(27.2)	31.5	N/A	N/A
Electric and renewable energy asset margins	143.7	83.3	122.7	72.5 %	(32.1)%
Realized retail natural gas margins	47.5	49.1	50.0 [4]	(3.3)%	(1.8)%
Realized wholesale natural gas margins	(0.6)[1]	3.9 [1]	(3.3)	N/A	N/A
Lower-of-cost-or-market inventory adjustments	4.4	(10.7)	6.8	N/A	N/A
Fair value accounting adjustments	2.1	(17.8)	8.2	N/A	N/A
Natural gas margins	53.4	24.5	61.7	118.0 %	(60.3)%
Operating and maintenance expense	106.0	105.5	116.1	0.5 %	(9.1)%
Net (gain) loss on Integrys Energy Services' dispositions related to strategy change	—	(0.3)	14.1	(100.0)%	N/A
Depreciation and amortization	10.3	10.3	11.8	— %	(12.7)%
Taxes other than income taxes	2.5	5.7	3.8	(56.1)%	50.0 %
Operating income (loss)	78.3	(13.4)	38.6	N/A	N/A
Earnings (losses) from equity method investments	1.1	(0.7)	(0.4)	N/A	75.0 %
Miscellaneous income	1.1	1.0	9.5	10.0 %	(89.5)%
Interest expense	(2.1)	(1.7)	(5.5)	23.5 %	(69.1)%
Other income (expense)	0.1	(1.4)	3.6	N/A	N/A
Income (loss) before taxes	$78.4	$(14.8)	$42.2	N/A	N/A
Physically settled volumes					
Retail electric sales volumes in kwh	13,343.1	12,416.5	12,647.9 [6]	7.5 %	(1.8)%
Wholesale electric sales volumes in kwh	92.7 [5]	84.7 [5]	1,086.5	9.4 %	(92.2)%
Retail natural gas sales volumes in bcf	130.0	125.5	133.3 [6]	3.6 %	(5.9)%
Wholesale natural gas sales volumes in bcf	—	—	27.5	N/A	(100.0)%

kwh – kilowatt-hours
bcf – billion cubic feet

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

(2) This amount includes negative margin of $1.4 million related to the settlement of retail supply contracts in connection with Integrys Energy Services' strategy change.

(3) This amount includes negative margin of $9.3 million related to the settlement of wholesale supply contracts in connection with Integrys Energy Services' strategy change.

(4) Amounts include margins in markets that Integrys Energy Services no longer considers strategic.

(5) Primarily relates to a renewable electric generation asset and distributed solar electric sales.

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

2012 Compared with 2011

Revenues

Integrys Energy Services' revenues decreased $154.6 million, primarily driven by lower average commodity prices, partially offset by higher retail electric sales volumes.

Margins

Integrys Energy Services' margins increased $89.3 million. The significant items contributing to the change in margins were as follows:

Electric and Renewable Energy Asset Margins

Realized retail electric margins

Realized retail electric margins decreased $7.2 million. The decrease was driven by the expiration of several large customer contracts in the Illinois market at the end of 2011. Continued competitive pressure on per-unit margins also contributed to the decrease in margins. These decreases were partially offset by higher sales volumes due to aggregated customer participation in Illinois, as well as higher sales volumes in the New York, Mid-Atlantic, New England, and Michigan markets.

Realized renewable energy asset margins

Realized renewable energy asset margins increased $2.8 million. The increase was driven by continued investment in solar energy projects.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $65.2 million increase in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $1.6 million. The decrease was primarily driven by warmer weather year over year.

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 $15.1 million increase in margins from inventory adjustments was driven by lower write-downs and a higher 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 $19.9 million increase in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income (Loss)

Integrys Energy Services' operating income increased $91.7 million. The main driver of the increase was the $89.3 million increase in margins discussed above. In addition, operating expenses decreased $2.4 million, driven by:

- A $4.6 million impairment loss recorded on a generation facility in 2011.

- A $3.2 million decrease in taxes other than income taxes.

- A $3.0 million decrease in fees related to an intercompany credit agreement with the holding company.

These decreases were partially offset by:

- A $4.3 million increase in professional fees, primarily related to the expansion of the residential and small commercial customer segment.
- A $4.0 million increase in bad debt expense, driven by the negative year over year impact of fewer recovery opportunities in 2012 compared with 2011.

2011 Compared with 2010

Revenues

Revenues decreased $417.2 million, driven by lower sales volumes resulting from Integrys Energy Services' strategy change, and lower year over year average commodity prices.

Margins

Integrys Energy Services' margins decreased $76.6 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 $13.1 million. 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 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 year over year increase. The increase was partially offset by a decrease in margins related to the sale of the Texas retail electric business in June 2010, resulting from Integrys Energy Services' strategy change.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $58.7 million decrease in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $0.9 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 $17.5 million year-over-year decrease in margins from inventory adjustments was driven by an increase in write-downs and 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 $26.0 million decrease in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income (Loss)

Integrys Energy Services' operating income decreased $52.0 million, driven by the $76.6 million decrease in margins discussed above, partially offset by a $24.6 million decrease in operating expenses.

The decrease in operating expense was primarily related to:

- A $14.4 million loss on dispositions in 2010 related to Integrys Energy Services' strategy change.

- A $6.5 million decrease in restructuring expense.

- A $4.5 million decrease in employee payroll and benefit related expenses, primarily due to the reduction in workforce associated with Integrys Energy Services' strategy change.

- A $2.2 million decrease in intercompany fees related to a credit agreement with the holding company.

These decreases were partially offset by:

- A $4.6 million impairment loss recorded on a generation facility in 2011.

Other Income (Expense)

Integrys Energy Services' other income decreased $5.0 million. The main driver for the decrease was an $8.5 million decrease in miscellaneous income. This decrease was driven by the negative year over year impact of a $4.3 million gain reclassified from accumulated OCI in 2010 related to foreign currency translation adjustments, and a $3.4 million decrease in interest income driven by the holding company's repayment of borrowings from Integrys Energy Services in the first quarter of 2011. The decrease in miscellaneous income was partially offset by 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)	Year Ended December 31 2012	2011	2010	Change in 2012 Over 2011	Change in 2011 Over 2010
Operating income (loss)	$(6.0)	$5.7	$8.3	N/A	(31.3)%
Other expense	(29.1)	(34.0)	(45.9)	(14.4)%	(25.9)%
Net loss before taxes	$(35.1)	$(28.3)	$(37.6)	24.0%	(24.7)%

2012 Compared with 2011

Operating Income

Operating income at the holding company and other segment decreased $11.7 million to an operating loss in 2012. The decrease was driven partially by operating losses at ITF. In addition, the holding company charged Integrys Energy Services $3.0 million less for fees related to decreased use of an intercompany credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $4.9 million in 2012. Interest expense on long-term debt decreased, driven by lower average outstanding long-term debt in 2012. The year over year impact of impairments recorded on an investment in 2011 also contributed to the decrease.

2011 Compared with 2010

Operating Income

Operating income at the holding company and other segment decreased $2.6 million. The decrease was driven primarily by lower intercompany fees charged by the holding company to Integrys Energy Services related to lower interest charges and decreased use of an intercompany credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $11.9 million. Interest expense on long-term debt decreased, driven by both lower interest rates on debt refinanced and lower average outstanding long-term debt in 2011.

Provision for Income Taxes

	Year Ended December 31		
	2012	2011	2010
Effective Tax Rate	33.8 %	36.7 %	39.8 %

2012 Compared with 2011

Our effective tax rate decreased in 2012. We effectively settled certain state income tax examinations and remeasured uncertain tax positions included in our liability for unrecognized tax benefits in 2012. We decreased our provision for income taxes $8.1 million in 2012 primarily related to the effective settlement and remeasurement of these positions. We also decreased the provision for income taxes $5.9 million as a result of WPS's 2013 rate case settlement agreement issued in December 2012. WPS recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. This legislation eliminated the tax deduction for retiree prescription drug payments that are paid by employers and are offset by the receipt of a federal Medicare Part D subsidy.

In 2011, we reduced the provision for income taxes by $5.8 million as a result of the 2012 rate orders for PGL and NSG. PGL and NSG recorded a regulatory asset after the rate order authorized recovery of deferred income taxes expensed in previous years also in connection with the 2010 federal health care reform. The decrease in the effective tax rate in 2011 was partially offset when we increased our state income tax obligations in 2011, driven by tax law changes in Michigan and Wisconsin. We increased the provision for income taxes by $6.0 million in 2011 when we increased our deferred income tax liabilities related to these tax law changes.

For information on changes in the deferred income tax balances, see Note 14, "Income Taxes."

2011 Compared with 2010

Our effective tax rate decreased during 2011. As discussed above, we reduced the provision for income taxes by $5.8 million in 2011 as a result of the 2012 rate orders for PGL and NSG. The decrease in the effective tax rate in 2011 was partially offset by the $6.0 million increase in our state income tax obligations for the tax law changes discussed above. In 2010, we expensed $10.8 million of deferred income taxes as a result of the 2010 federal health care reform.

Discontinued Operations, Net of Tax

	Year Ended December 31			Change in	Change in
(Millions)	2012	2011	2010	2012 Over 2011	2011 Over 2010
Discontinued operations, net of tax	$(9.7)	$0.5	$(21.5)	N/A	N/A

2012 Compared with 2011

Income from discontinued operations, net of tax, decreased $10.2 million in 2012. In 2012, Integrys Energy Services recognized $5.7 million of after tax impairment losses on generation facilities classified as held for sale that met the criteria for discontinued operations. See Note 4, "Dispositions," for more information. In addition, operating results at one of the generation facilities were negatively impacted when a long-term capacity contract expired in the fourth quarter of 2011. Discontinued operations decreased $3.8 million after tax related to the decrease in revenues.

2011 Compared with 2010

The loss from discontinued operations, net of tax, decreased $22.0 million in 2011. In 2010, Integrys Energy Services recognized impairment losses on generation facilities classified as held for sale that subsequently met the criteria for discontinued operations during 2012. See Note 4, "Dispositions," for more information.

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

2012 Compared with 2011

Net cash provided by operating activities was $569.0 million during 2012, compared with $717.8 million during 2011. The $148.8 million decrease in net cash provided by operating activities was largely driven by a $156.0 million year-over-year increase in contributions to pension and other postretirement benefit plans.

2011 Compared with 2010

Net cash provided by operating activities was $717.8 million during 2011, compared with $714.7 million during 2010. The $3.1 million increase in net cash provided by operating activities was mainly driven by:

- A $69.9 million net decrease in contributions to pension and other postretirement benefit plans.

- The increase in net cash provided by operating activities was partially offset by net cash used for working capital of $29.8 million in 2011, compared with $36.5 million of net cash provided by working capital in 2010. The $66.3 million year-over-year increase in working capital requirements was primarily due to:

A $17.3 million increase in cash collateral provided to counterparties in 2011, compared with a $163.6 million decrease in cash collateral provided in 2010, primarily due to the change in Integrys Energy Services' business related to its strategy change.

Inventory levels increased $37.1 million in 2011, compared to a decrease of $49.6 million in 2010. The increase in inventory in 2011 was driven by warmer weather at the end of 2011 compared to the end of 2010, which impacted inventory levels at PGL and NSG, and increased coal freight costs at WPS. The decrease in inventory in 2010 was largely due to the impact of the Integrys Energy Services' strategy change.

Partially offsetting these changes was the positive impact from a $55.3 million decrease in other current assets in 2011, compared with a $84.3 million increase in other current assets in 2010. This change was driven by the year-over-year increase in net cash received for income taxes, which was primarily due to the 100% bonus tax depreciation allowed in 2011.

Also partially offsetting these changes was a $77.6 million year-over-year positive impact from the change in other current liabilities. The change was driven by the return of collateral to counterparties in 2010 as a result of Integrys Energy Services' strategy change.

Investing Cash Flows

2012 Compared with 2011

Net cash used for investing activities was $605.0 million during 2012, compared with $393.5 million during 2011. The $211.5 million increase in net cash used for investing activities was primarily driven by a $284.2 million increase in cash used to fund capital expenditures (discussed below). Partially offsetting the increase in capital expenditures was a $43.9 million year-over-year impact related to the acquisition of the compressed natural gas fueling businesses in 2011.

2011 Compared with 2010

Net cash used for investing activities was $393.5 million during 2011, compared with $198.6 million during 2010. The $194.9 million increase in net cash used for investing activities was primarily driven by:

- A $58.4 million decrease in proceeds received from the sale or disposal of assets. The proceeds received in 2010 primarily related to the Integrys Energy Services' strategy change.
- A $52.4 million increase in cash used to fund capital expenditures (discussed below).
- In 2011, $42.6 million of net cash was used for the acquisition of the Pinnacle and Trillium compressed natural gas fueling businesses.
- A $30.7 million year-over-year increase in capital contributions to equity method investments, mainly due to increased contributions to INDU Solar Holdings, LLC.

Capital Expenditures

Capital expenditures by business segment for the years ended December 31 were as follows:

Reportable Segment (millions)	2012	2011	2010
Natural gas utility	$375.1	$199.3	$133.6
Electric utility	163.9	84.1	87.2
Integrys Energy Services	30.9	16.7	14.1
Holding company and other	24.4	10.0	22.8
Integrys Energy Group consolidated	$594.3	$310.1	$257.7

The increase in capital expenditures at the natural gas utility segment in 2012 compared with 2011 was primarily a result of the AMRP at PGL. The increase in capital expenditures at the electric utility segment was driven by environmental compliance projects at the Columbia plant in 2012. The increase in capital expenditures at the Integrys Energy Services segment was primarily a result of increased solar investments during 2012. Capital expenditures increased at the holding company and other segment, primarily due to increased software project expenditures.

The increase in capital expenditures at the natural gas utility segment in 2011 compared with 2010 was primarily a result of the AMRP at PGL. Partially offsetting this increase was a decrease in capital expenditures at the holding company and other segment, primarily due to lower software project expenditures in 2011.

Financing Cash Flows

2012 Compared with 2011

Net cash provided by financing activities was $55.1 million during 2012, compared with net cash used for financing activities of $478.1 million during 2011. The $533.2 million positive impact related to financing activities was primarily driven by:

- A $665.6 million positive impact due to $149.8 million of net issuances of long-term debt in 2012, compared with $515.8 million of net repayments of long-term debt in 2011.

- A $45.5 million increase in cash received from stock option exercises.

- Partially offsetting these positive impacts were:

A $124.2 million decrease in net borrowings of commercial paper.

A $72.9 million increase in cash used to purchase our common stock on the open market to satisfy stock-based compensation obligations.

2011 Compared with 2010

Net cash used for financing activities was $478.1 million during 2011, compared with $391.4 million during 2010. The $86.7 million increase in net cash used for financing activities was primarily driven by:

- A $648.6 million increase due to $515.8 million of net repayments of long-term debt in 2011, compared with $132.8 million of net long-term issuances in 2010.

- A $20.3 million increase in cash used for the payment of common stock dividends.

- A $15.4 million decrease in net proceeds from the sale of borrowed natural gas related to the strategy change at Integrys Energy Services.

- A $14.9 million increase in cash used to purchase our common stock on the open market to satisfy stock-based compensation obligations.

- A $12.6 million decrease in cash provided by the issuance of common stock. See "Significant Financing Activities" for more information.

Partially offsetting these increases in net cash used were:

- A $505.4 million decrease due to $293.3 million of net borrowings of short-term debt and notes payable in 2011, compared with
$212.1 million of net repayments in 2010.

- A $125.9 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 $98.1 million decrease related to the settlement of certain contracts that were executed at the time of sale.

Significant Financing Activities

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

Period	Method of meeting requirements
Beginning 02/05/2013	Issuing new shares
05/01/2011 – 02/04/2013	Purchased shares on the open market
02/11/2010 – 04/30/2011	Issued new shares
01/01/2010 – 02/10/2010	Purchased shares on the open market

For information on short-term debt, see Note 11, "Short-Term Debt and Lines of Credit."

For information on the issuance and redemption of our long-term debt and that of our subsidiaries, see Note 12, "Long-Term Debt."

Credit Ratings

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

Credit Ratings	Standard & Poor's	Moody's
Integrys Energy Group		
Issuer credit rating	A-	N/A
Senior unsecured debt	BBB+	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	A-	A3
Senior secured debt	A	A1
Commercial paper	A-2	P-2
NSG		
Issuer credit rating	A-	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 February 15, 2013, Standard & Poor's raised PGL's senior secured debt rating to "A" from "A-." PGL's revised rating reflects Standard & Poor's revision to its methodology for assigning recovery ratings for senior bonds secured by utility real property.

Discontinued Operations

These cash flows primarily relate to the operations of WPS Westwood Generation, LLC, WPS Beaver Falls Generation, LLC, WPS Syracuse Generation, LLC, and Combined Locks Energy Center, LLC. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Discontinued Operations, Net of Tax," and Note 4, "Dispositions," for more information.

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2012, including those of our subsidiaries.

		Payments Due By Period			
(Millions)	Total Amounts Committed	2013	2014 to 2015	2016 to 2017	2018 and Later Years
Long-term debt principal and interest payments (1)	$3,429.5	$419.1	$403.2	$632.5	$1,974.7
Operating lease obligations	89.3	8.5	10.0	10.5	60.3
Energy and transportation purchase obligations (2)	2,395.4	844.7	525.2	226.1	799.4
Purchase orders (3)	562.0	560.1	1.9	—	—
Capital contributions to equity method investment	1.7	1.7	—	—	—
Pension and other postretirement funding obligations (4)	601.7	100.8	170.1	60.8	270.0
Uncertain tax positions	7.3	7.3	—	—	—
Total contractual cash obligations	$7,086.9	$1,942.2	$1,110.4	$929.9	$3,104.4

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

(2) Energy and related commodity supply contracts at Integrys Energy Services included as part of energy and transportation purchase obligations are primarily entered into to meet future obligations to deliver energy and related products to customers; therefore, these costs will be recovered as customer sales contracts settle. 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 2017.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $650.0 million at December 31, 2012, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 15, "Commitments and Contingencies," for more information about environmental liabilities. The table also does not reflect estimated future payments for the December 31, 2012 liability of $3.5 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 14, "Income Taxes," for more information on unrecognized tax benefits.

Capital Requirements

As of December 31, 2012, our capital expenditures by segment for 2013 through 2015 were expected to be as follows:

(Millions)	
Natural Gas Utility	
Distribution projects and underground storage facilities	$1,073
Other projects	70
Electric Utility	
Environmental projects	419

Acquisition of Fox Energy Center	390
Distribution and energy supply operations projects	347
Other projects	57
Integrys Energy Services	
Solar and other projects	145
Holding Company and Other	
Compressed natural gas fueling stations	158
Corporate or shared services software and infrastructure projects	152
Repairs and safety measures at nonutility hydroelectric facilities	3
Total capital expenditures	$2,814

We expect to provide capital contributions to ATC (not included in the above table) of approximately $56 million from 2013 through 2015.

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

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management 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 2013 through 2015 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.

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

WPS currently has two shelf registration statements. Under these registration statements, WPS may issue up to $200.0 million of additional senior debt securities and up to $30.0 million of preferred stock. Amounts, prices, and terms will be determined at the time of future offerings.

At December 31, 2012, 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 11, "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 12, "Long-Term Debt," for more information on long-term debt and related covenants.

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. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 19, "Common Equity," for more information on dividend restrictions.

Other Future Considerations

Decoupling

The Illinois Attorney General is currently appealing the ICC's authority to approve PGL's and NSG's permanent decoupling mechanism. As a result, revenues collected under this mechanism are potentially subject to refund. Therefore, beginning in the second quarter of 2012, PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In November 2012, PGL and NSG filed briefs with the Illinois Appellate Court defending the authority of the ICC to approve the decoupling mechanism. Since the decoupling mechanism is still in place, PGL and NSG also intend to file with the ICC for rate recovery, beginning in April 2013, for amounts accrued related to decoupling.

See Note 25, "Regulatory Environment," for more information on all of our subsidiaries' decoupling mechanisms.

Climate Change

The EPA began regulating greenhouse gas emissions under the Clean Air Act in January 2011 by applying the Best Available Control Technology (BACT) requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In March 2012, the EPA issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units. The proposed limit may prevent the construction of new coal units until technology becomes commercially available. The EPA planned to propose performance standards for existing units in 2011 and finalize them in 2012; however, that proposal has been delayed.

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

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

Federal Health Care Reform

Since the Health Care and Education Reconciliation Act of 2010 (HCR) was enacted, we have worked to create a long-term strategy for its implementation. With the Supreme Court's decision in 2012 to uphold HCR's individual mandate, the implementation of this strategy continues. Our focus is on continued compliance with the law's many mandates, avoidance or reduction of adverse tax impacts, and cost management.

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

The Dodd-Frank Act was signed into law in July 2010. Significant rulings essential to its framework are now becoming effective for certain companies. Since some of these final rules are being challenged in court, it is difficult to predict how they will ultimately affect us. Certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. We continue to monitor developments related to this act and their potential impacts on our future financial results. At this time, we are making the necessary system and process changes to comply with the known rules.

Federal Tax Law Changes

In January 2013, President Obama signed into law the American Taxpayer Relief Act of 2012. This act extends 50% bonus tax depreciation through 2013 for most capital expenditures. This bonus tax depreciation extension is anticipated to generate future cash flows in excess of approximately $101 million through 2015.

In December 2011, the National Defense Authorization Act (NDAA) was enacted. The most relevant provision of the NDAA was to retroactively eliminate the application of the tax normalization rule for cash grants taken by a regulated utility in lieu of investment tax credits or production tax credits. Prior to the enactment of NDAA, a regulated utility was required to amortize the grant in rates over the life of the renewable energy generating plant. Further, the allowed rate base on the generating plant could not be reduced by the unamortized grant balance during the life of the plant. In 2012, we elected to claim and subsequently received a $69.0 million Section 1603 Grant for WPS's Crane Creek Wind Project in lieu of the production tax credit. The cost of eliminating the prior production tax credit was recorded as a regulatory asset at December 31, 2012. Therefore, we do not anticipate a significant financial impact as a result of this change.

Illinois Senate Bill 1665

In February 2013, the Illinois Senate introduced Senate Bill 1665, The Natural Gas Modernization, Public Safety and Jobs Bill. This bill, if passed, would give Illinois natural gas utilities greater regulatory certainty, allowing them to accelerate investment in natural gas infrastructure modernization. It would establish a built-in formula for setting rates, including a pre-defined return on investment based on U.S. Treasury Bond rates, and strict rate caps.

OFF BALANCE SHEET ARRANGEMENTS

See Note 16, "Guarantees," for information regarding guarantees.

CRITICAL ACCOUNTING POLICIES

We have determined that the following accounting policies are critical to the understanding of our financial statements because their application requires significant judgment and reliance on estimations of matters that are inherently uncertain. Our management has discussed these critical accounting policies with the Audit Committee of the Board of Directors.

Risk Management Activities

We have entered into contracts that are accounted for as derivatives. All derivative contracts are recorded at fair value on the balance sheets, unless they qualify for the normal purchases and sales exception, which provides that recognition of gains and losses in the financial statements is not required until the settlement of the contracts. Changes in fair value, except effective portions of derivative instruments designated as hedges or qualifying for regulatory deferral, generally affect net income attributed to common shareholders at each financial reporting date until the contracts are ultimately settled.

We have based our valuations on observable inputs whenever possible. However, at times, the valuation of certain derivative instruments requires the use of internally developed valuation techniques and/or significant unobservable inputs. These valuations require a significant amount of management judgment and are classified as Level 3 measurements in the fair value hierarchy. Of the total risk management assets on our balance sheets, $19.6 million (10.3%) were classified as Level 3 measurements. Of the total risk management liabilities, $24.5 million (10.2%) were classified as Level 3 measurements. We believe these valuations represent the fair values of these instruments as of the reporting date; however, the actual amounts realized upon settlement of these instruments could vary materially from the reported amounts due to movements in market prices and changes in the liquidity of certain markets.

As a component of fair value determinations, we consider counterparty credit risk and our own credit risk. Changes in the underlying assumptions for the credit risk component of fair value at December 31, 2012, would have had the following effects:

Change in Risk Components	Effect on Fair Value of Net Risk Management Liabilities
(Millions)	at December 31, 2012
100% increase	$0.4 decrease
50% decrease	$0.2 increase

These hypothetical changes in fair value would impact current and long-term assets and liabilities from risk management activities on the balance sheets and nonregulated revenues on the income statements.

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2012. 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 (ROE) for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is determined based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is based on its current allowed ROE adjusted for forecasted disallowed costs and expectations regarding the direction and magnitude of movements in interest rates. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

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

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

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

The fair values calculated in the first step of the test for MGU, MERC, and PGL exceeded the carrying values by approximately 3% - 20%. Due to the subjectivity of the assumptions and estimates underlying the impairment analyses, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, which would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test.

Change in key inputs (in basis points)	MGU	MERC	PGL
Discount rate	25	75	250
Terminal year return on equity	(100)	(235)	(670)
Terminal year growth rate	(50)	(100)	N/A *

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

Accrued Unbilled Revenues

We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. Significant changes in these judgments and assumptions could have a material impact on our results of operations. At December 31, 2012, and 2011, our unbilled revenues were $298.2 million and $282.1 million, respectively. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer use patterns, commodity prices, and customer mix.

Pension and Other Postretirement Benefits

The costs of providing noncontributory defined benefit pension benefits and other postretirement benefits, described in Note 17, "Employee Benefit Plans," are dependent on numerous factors resulting from actual plan experience and assumptions regarding future experience.

Pension and other postretirement benefit costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and other postretirement benefit costs may be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and other postretirement benefit costs.

Pension and other postretirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered/refunded at the regulated utility segments through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (Millions, except percentages)	Percentage-Point Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2012 Pension Cost
Discount rate	(0.5)	$118.9	$10.0
Discount rate	0.5	(99.2)	(8.0)
Rate of return on plan assets	(0.5)	N/A	6.5
Rate of return on plan assets	0.5	N/A	(6.5)

The following table shows how a given change in certain actuarial assumptions would impact the accumulated other postretirement benefit obligation and the reported net periodic other postretirement benefit cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (Millions, except percentages)	Percentage-Point Change in Assumption	Impact on Postretirement Benefit Obligation	Impact on 2012 Postretirement Benefit Cost
Discount rate	(0.5)	$43.4	$3.6
Discount rate	0.5	(40.4)	(2.7)
Health care cost trend rate	(1.0)	(69.7)	(9.6)
Health care cost trend rate	1.0	85.4	13.3
Rate of return on plan assets	(0.5)	N/A	1.7
Rate of return on plan assets	0.5	N/A	(1.7)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds with maturities between 0 and 30 years. The bonds are generally rated "Aa" with a minimum amount outstanding of $50 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on asset assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return was 8.25% in both 2012 and 2011, and 8.50% in 2010. For 2012, 2011, and 2010, the actual rates of return on pension plan assets, net of fees, were 14.3%, 1.5%, and 13.0%, respectively. Beginning in 2013, the expected return on assets assumption for the plans is 8.00%.

The determination of expected return on qualified plan assets is based on a market-related valuation of assets, which reduces year-to-year volatility. Cumulative gains and losses in excess of 10% of the greater of the pension or other postretirement benefit obligation or market-related value are amortized over the average remaining future service to expected retirement ages. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by WPS, while differences between actual investment returns and the expected return on plan assets are recognized over a five-year period for pension plans sponsored by IBS and PELLC. Because of this method, the future value of assets will be impacted as previously deferred gains or losses are included in market-related value.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and other postretirement benefits, see Note 17, "Employee Benefit Plans."

Regulatory Accounting

Our natural gas and electric utility segments follow the guidance under the Regulated Operations Topic of the FASB ASC. Our financial statements reflect the effects of the ratemaking principles followed by the various jurisdictions regulating these segments. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery period. If recovery or refund of costs is not approved or is no longer deemed probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, earnings at the natural gas and electric utility segments, and the status of any pending or potential deregulation legislation.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our natural gas and electric utility segment's operations no longer meet the criteria for application. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2012, would result in an 18.6% decrease in total assets and a 6.0% decrease in total liabilities. The two largest regulatory assets at December 31, 2012, related to unrecognized pension and other postretirement benefit costs and environmental remediation costs. A write-off of the unrecognized pension and other postretirement benefit related regulatory asset at December 31, 2012, would result in a 7.8% decrease in total assets. A write-off of the regulatory asset related to environmental remediation costs at December 31, 2012, would result in a 6.7% decrease in total assets. See Note 7, "Regulatory Assets and Liabilities," for more information.

Income Tax Provision

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to the provision for income taxes in the income statements.

Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(p), "Income Taxes," and Note 14, "Income Taxes," for a discussion of accounting for income taxes.

IMPACT OF INFLATION

Our financial statements are prepared in accordance with GAAP. The statements provide a reasonable, objective, and quantifiable statement of financial results, but generally do not evaluate the impact of inflation. To the extent our regulated operations are not recovering the effects of inflation, they will file rate cases as necessary in the various jurisdictions in which they operate. Our nonregulated businesses include inflation in forecasted costs, which impacts product pricing.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have potential market risk exposure related to commodity price 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 we use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

Utilities

Prudent fuel and purchased power costs and capacity payments are recovered from customers under one-for-one recovery mechanisms by UPPCO, and by the wholesale electric operations and Michigan retail electric operations of WPS. Prudently incurred costs of natural gas used by the natural gas utilities are also recovered from customers under one-for-one recovery mechanisms. These recovery mechanisms greatly reduce commodity price risk for the utilities.

WPS's Wisconsin retail electric operations do not have a one-for-one recovery mechanism for price fluctuations. Instead, a "fuel window" mechanism substantially mitigates this price risk.

To manage commodity price risk for their customers, the regulated utilities enter into fixed-price contracts of various durations for the purchase and/or sale of natural gas, fuel for electric generation, and electricity. In addition, the electric operations of WPS and UPPCO, and the natural gas operations of WPS, PGL, NSG, and MERC, employ risk management techniques, which include the use of derivative instruments such as swaps, futures, and options.

See Note 1(f), "Summary of Significant Accounting Policies – Revenues and Customer Receivables," for more information.

Integrys Energy Services

Integrys Energy Services seeks to reduce market price risk from its generation and energy supply portfolios through the use of various financial and physical instruments. Additionally, Integrys Energy Services uses volume limits and stop loss limits as defined in its Risk Policy to limit its exposure to commodity price movements.

To measure commodity price risk exposure, Integrys Energy Services employs a number of controls and processes, including a value-at-risk (VaR) analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors, within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with its open commodity positions (primarily natural gas and power positions).

The VaR calculation includes financial and physical commodity instruments, such as forwards, futures, swaps, and options, as well as natural gas inventory, natural gas storage, and transportation contracts, to the extent such positions are significant. The VaR calculation excludes the positions created by owning energy assets and associated coal, sulfur dioxide emission allowances, renewable energy credits, and other ancillary fuels. Additionally, financial transmission rights, certain electric ancillary services, and certain portions of long-dated natural gas storage and transportation contracts are also excluded from the VaR calculation. VaR is calculated using nondiscounted 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 a 99% confidence level.

The VaR model is not intended to represent actual losses in fair value that we expect to incur, but is used as a risk estimation and management tool.

The VaR for Integrys Energy Services' portfolio at a 95% confidence level and a one-day holding period is presented in the following table:

(Millions)	2012	2011
As of December 31	$0.1	$0.2
Average for 12 months ended December 31	0.1	0.2
High for 12 months ended December 31	0.2	0.3
Low for 12 months ended December 31	0.1	0.1

The VaR for Integrys Energy Services' portfolio at a 99% confidence level and a ten-day holding period is presented in the following table:

(Millions)	2012	2011
As of December 31	$0.6	$0.7
Average for 12 months ended December 31	0.5	0.7
High for 12 months ended December 31	0.7	1.2
Low for 12 months ended December 31	0.4	0.5

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 our short-term commercial paper borrowings and projected near-term debt financing needs. 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 our variable rate debt outstanding at December 31, 2012, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $4.8 million. Comparatively, based on the variable rate debt outstanding at December 31, 2011, an increase in interest rates of 100 basis points would have increased annual interest expense by $3.3 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.

Equity Return and Principal Preservation Risk

We currently fund liabilities related to employee benefits through various external trust funds. The trust funds are managed by numerous investment managers and hold investments primarily in debt and equity securities. Changes in the market value of these investments can have an impact on the future expenses related to these liabilities. Declines in the equity markets or declines in interest rates may result in increased future costs for the plans and require additional contributions into the plans. We monitor the trust fund portfolio by benchmarking the performance of the investments against certain security indices. Most of the employee benefit costs relate to the regulated utilities. As such, the majority of these costs are recovered in customers' rates, reducing most of the equity return and principal preservation risk on these exposures. Also, the likelihood of an increase in the employee benefit obligations, which the investments must fund, has been partially mitigated as a result of certain employee groups no longer being eligible to participate in, or accumulate benefits in, certain pension and other postretirement benefit plans. Our defined benefit pension plans are closed to all new hires.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Integrys Energy Group and our subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting. Our control systems were designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on this assessment, management believes that, as of December 31, 2012, our internal control over financial reporting is effective.

Our independent registered public accounting firm has issued an audit report on the effectiveness of our internal control over financial reporting.

B. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Integrys Energy Group, Inc.:

We have audited the internal control over financial reporting of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2012 of the Company, and our report dated February 28, 2013 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
February 28, 2013

C. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 (Millions, except per share data)	2012	2011	2010
Utility revenues	$2,959.5	$3,294.5	$3,368.5
Nonregulated revenues	1,252.9	1,391.4	1,801.3
Total revenues	4,212.4	4,685.9	5,169.8
Utility cost of fuel, natural gas, and purchased power	1,326.3	1,635.3	1,685.5
Nonregulated cost of sales	1,040.2	1,274.2	1,611.4
Operating and maintenance expense	1,031.3	1,025.1	1,043.7
Net (gain) loss on Integrys Energy Services' dispositions related to strategy change	—	(0.3)	14.1
Depreciation and amortization expense	250.7	247.7	260.4
Taxes other than income taxes	96.4	97.1	92.0
Operating income	467.5	406.8	462.7
Earnings from equity method investments	87.2	79.4	78.2
Miscellaneous income	9.3	5.3	13.3
Interest expense	(120.2)	(128.2)	(146.7)
Other expense	(23.7)	(43.5)	(55.2)
Income before taxes	443.8	363.3	407.5
Provision for income taxes	149.8	133.3	162.3
Net income from continuing operations	294.0	230.0	245.2
Discontinued operations, net of tax	(9.7)	0.5	(21.5)
Net income	284.3	230.5	223.7
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.2	—	0.3
Net income attributed to common shareholders	$281.4	$227.4	$220.9
Average shares of common stock			
Basic	78.6	78.6	77.5
Diluted	79.3	79.1	78.0
Earnings (loss) per common share (basic)			
Net income from continuing operations	$3.70	$2.89	$3.13
Discontinued operations, net of tax	(0.12)	—	(0.28)
Earnings per common share (basic)	$3.58	$2.89	$2.85
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$3.67	$2.87	$3.11
Discontinued operations, net of tax	(0.12)	—	(0.28)
Earnings per common share (diluted)	$3.55	$2.87	$2.83
Dividends per common share declared	$2.72	$2.72	$2.72

The accompanying notes to the consolidated financial statements are an integral part of these statements.

D. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (Millions)	2012	2011	2010
Net income	$284.3	$230.5	$223.7
Other comprehensive income (loss), net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of $(0.1) million, $0.4 million, and $(22.3) million, respectively	(0.2)	1.5	(22.1)
Reclassification of net losses to net income, net of tax of $2.0 million, $4.4 million, and $27.0 million, respectively	6.5	7.4	26.6
Cash flow hedges, net	6.3	8.9	4.5
Defined benefit pension plans			
Pension and other postretirement benefit costs arising during period, net of tax of $(4.4) million, $(5.7) million, and $(2.3) million, respectively	(6.1)	(7.5)	(3.3)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $1.0 million, $0.6 million, and $0.3 million, respectively	1.4	0.8	0.5
Defined benefit pension plans, net	(4.7)	(6.7)	(2.8)
Foreign currency translation			
Foreign currency translation adjustments arising during period net of tax of $ — million, $ — million, and $0.1 million, respectively	—	—	0.3
Foreign currency translation gain included in net income as a result of the Integrys Energy Services' strategy change, net of tax $ — million, $ — million, and $(1.6) million, respectively	—	—	(2.7)
Foreign currency translation , net	—	—	(2.4)
Other comprehensive income (loss), net of tax	1.6	2.2	(0.7)
Comprehensive income	285.9	232.7	223.0
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.2	—	0.3
Comprehensive income attributed to common shareholders	$283.0	$229.6	$220.2

The accompanying notes to the consolidated financial statements are an integral part of these statements.

E. CONSOLIDATED BALANCE SHEETS

At December 31 (Millions)	2012	2011
Assets		
Cash and cash equivalents	$27.4	$28.1
Collateral on deposit	41.0	50.9
Accounts receivable and accrued unbilled revenues, net of reserves of $43.5 and $47.1, respectively	796.8	737.7
Inventories	271.9	297.6
Assets from risk management activities	145.4	227.2
Regulatory assets	110.8	125.1
Assets held for sale	10.1	28.8
Deferred income taxes	64.3	94.2
Prepaid taxes	152.8	209.6
Other current assets	38.6	29.0
Current assets	1,659.1	1,828.2
Property, plant, and equipment, net of accumulated depreciation of $3,114.7 and $3,006.6, respectively	5,501.9	5,175.5
Regulatory assets	1,813.8	1,658.5
Assets from risk management activities	45.3	64.4
Equity method investments	512.2	476.3
Goodwill	658.3	658.4
Other long-term assets	136.8	121.9
Total assets	$10,327.4	$9,983.2
Liabilities and Equity		
Short-term debt	$482.4	$303.3
Current portion of long-term debt	313.5	250.0
Accounts payable	457.7	426.6
Liabilities from risk management activities	181.9	311.5
Accrued taxes	83.0	70.5
Regulatory liabilities	65.6	67.5
Liabilities held for sale	0.2	27.3
Other current liabilities	229.0	217.0
Current liabilities	1,813.3	1,673.7
Long-term debt	1,931.7	1,845.0
Deferred income taxes	1,203.8	1,070.7
Deferred investment tax credits	49.3	44.0
Regulatory liabilities	370.5	332.5
Environmental remediation liabilities	651.5	615.1
Pension and other postretirement benefit obligations	625.2	749.3
Liabilities from risk management activities	58.4	102.0
Asset retirement obligations	411.2	397.2
Other long-term liabilities	135.7	141.1
Long-term liabilities	5,437.3	5,296.9

Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,902,467 shares outstanding	78.3	78.3
Additional paid-in capital	2,574.6	2,579.1
Retained earnings	431.5	363.6
Accumulated other comprehensive loss	(40.9)	(42.5)
Shares in deferred compensation trust	(17.7)	(17.1)
Total common shareholders' equity	3,025.8	2,961.4
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding	51.1	51.1
Noncontrolling interest in subsidiaries	(0.1)	0.1
Total liabilities and equity	$10,327.4	$9,983.2

The accompanying notes to the consolidated financial statements are an integral part of these statements.

F. CONSOLIDATED STATEMENTS OF EQUITY

	Integrys Energy Group Common Shareholders' Equity								
(Millions)	Shares in Deferred Compensation Trust	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Noncontrolling Interest in Subsidiaries	Total Equity
Balance at December 31, 2009	$(17.2)	$76.4	$2,497.8	$337.0	$(44.0)	$2,850.0	$51.1	$(0.9)	$2,900.2
Net income attributed to common shareholders	—	—	—	220.9	—	220.9	—	(0.3)	220.6
Other comprehensive loss	—	—	—	—	(0.7)	(0.7)	—	—	(0.7)
Issuance of common stock	—	1.3	54.5	—	—	55.8	—	—	55.8
Stock based compensation	—	—	4.0	—	—	4.0	—	—	4.0
Dividends on common stock	—	—	—	(208.7)	—	(208.7)	—	—	(208.7)
Other	(1.3)	0.1	(15.9)	1.6	—	(15.5)	—	1.3	(14.2)
Balance at December 31, 2010	$(18.5)	$77.8	$2,540.4	$350.8	$(44.7)	$2,905.8	$51.1	$0.1	$2,957.0
Net income attributed to common shareholders	—	—	—	227.4	—	227.4	—	—	227.4
Other comprehensive income	—	—	—	—	2.2	2.2	—	—	2.2
Issuance of common stock	—	0.5	21.7	—	—	22.2	—	—	22.2
Stock based compensation	—	—	7.5	(2.1)	—	5.4	—	—	5.4
Dividends on common stock	—	—	—	(211.8)	—	(211.8)	—	—	(211.8)
Other	1.4	—	9.5	(0.7)	—	10.2	—	—	10.2
Balance at December 31, 2011	$(17.1)	$78.3	$2,579.1	$363.6	$(42.5)	$2,961.4	$51.1	$0.1	$3,012.6
Net income attributed to common shareholders	—	—	—	281.4	—	281.4	—	(0.2)	281.2

Other comprehensive income	—	—	—	—	1.6	1.6	—	—	1.6
Issuance of common stock	—	—	—	—	—	—	—	—	—
Stock based compensation	—	—	(4.1)	(0.7)	—	(4.8)	—	—	(4.8)
Dividends on common stock	—	—	—	(211.9)	—	(211.9)	—	—	(211.9)
Other	(0.6)	—	(0.4)	(0.9)	—	(1.9)	—	—	(1.9)
Balance at December 31, 2012	$(17.7)	$78.3	$2,574.6	$431.5	$ (40.9)	$ 3,025.8	$ 51.1	$ (0.1)	$3,076.8

The accompanying notes to the consolidated financial statements are an integral part of these statements.

G. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (Millions)	2012	2011	2010
Operating Activities			
Net income	$284.3	$230.5	$223.7
Adjustments to reconcile net income to net cash provided by operating activities			
Discontinued operations, net of tax	9.7	(0.5)	21.5
Depreciation and amortization expense	250.7	247.7	260.4
Recoveries and refunds of regulatory assets and liabilities	49.9	56.1	28.7
Net unrealized (gains) losses on energy contracts	(40.3)	45.2	(51.4)
Bad debt expense	26.2	35.0	48.0
Pension and other postretirement expense	62.1	59.9	67.5
Pension and other postretirement contributions	(287.5)	(131.5)	(201.4)
Deferred income taxes and investment tax credits	148.2	174.1	250.5
Equity income, net of dividends	(17.5)	(14.8)	(14.5)
Other	20.1	45.9	45.2
Changes in working capital			
Collateral on deposit	9.6	(17.3)	163.6
Accounts receivable and accrued unbilled revenues	(26.2)	93.4	97.8
Inventories	28.5	(37.1)	49.6
Other current assets	6.1	55.3	(84.3)
Accounts payable	22.0	(37.3)	(25.8)
Other current liabilities	23.1	(86.8)	(164.4)
Net cash provided by operating activities	569.0	717.8	714.7
Investing Activities			
Capital expenditures	(594.3)	(310.1)	(257.7)
Proceeds from the sale or disposal of assets	10.4	7.6	66.0
Capital contributions to equity method investments	(27.4)	(37.6)	(6.9)
Acquisition of compressed natural gas fueling companies, net of cash acquired	1.3	(42.6)	—
Other	5.0	(10.8)	—
Net cash used for investing activities	(605.0)	(393.5)	(198.6)
Financing Activities			
Short-term debt, net	179.1	303.3	(212.1)
Repayment of notes payable	—	(10.0)	—
Proceeds from sale of borrowed natural gas	—	—	21.9
Purchase of natural gas to repay natural gas loans	—	—	(6.5)
Issuance of long-term debt	428.0	50.0	250.0
Repayment of long-term debt	(278.2)	(565.8)	(117.2)
Proceeds from stock option exercises	55.8	10.3	18.8
Shares purchased for stock-based compensation	(89.9)	(17.0)	(2.1)
Payment of dividends			
Preferred stock of subsidiary	(3.1)	(3.1)	(3.1)
Common stock	(211.9)	(206.4)	(186.1)
Issuance of common stock	—	2.0	14.6

Payments made on derivative contracts related to divestitures classified as financing activities	(23.7)	(31.9)	(157.8)
Other	(1.0)	(9.5)	(11.8)
Net cash provided by (used for) financing activities	55.1	(478.1)	(391.4)
Change in cash and cash equivalents – continuing operations	19.1	(153.8)	124.7
Change in cash and cash equivalents – discontinued operations			
Net cash provided by operating activities	4.8	4.1	10.5
Net cash provided by (used for) investing activities	2.4	(0.9)	(0.7)
Net cash used for financing activities	(27.0)	(0.3)	—
Net change in cash and cash equivalents	(0.7)	(150.9)	134.5
Cash and cash equivalents at beginning of year	28.1	179.0	44.5
Cash and cash equivalents at end of year	$27.4	$28.1	$179.0

The accompanying notes to the consolidated financial statements are an integral part of these statements.

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—We are a holding company whose primary wholly owned subsidiaries at December 31, 2012, included MERC, MGU, NSG, PGL, UPPCO, WPS, IBS, Integrys Energy Services, and ITF. Of these subsidiaries, six are regulated electric and/or natural gas utilities, one, IBS, is a centralized service company, one, Integrys Energy Services, is a nonregulated retail energy supply and services company, and one, ITF, is a nonregulated compressed natural gas fueling business. In addition, we have an approximate 34% interest in ATC.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the consolidated statements of income, consolidated statements of comprehensive income, consolidated balance sheets, consolidated statements of equity, and consolidated statements of cash flows, unless otherwise noted.

The term "utility" refers to the regulated activities of the electric and natural gas utility companies, while the term "nonutility" refers to the activities of the electric and natural gas utility companies that are not regulated. The term "nonregulated" refers to activities at Integrys Energy Services, ITF, the Integrys Energy Group holding company, and the PELLC holding company.

(b) Consolidated Basis of Presentation—The financial statements include our accounts and the accounts of all of our majority owned subsidiaries, after eliminating intercompany transactions and balances. These financial statements also reflect our proportionate interests in certain jointly owned utility facilities. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. Investments in businesses not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. For more information on equity method investments, see Note 8, "Equity Method Investments."

(c) Reclassifications—We reclassified $49.0 million of materials and supplies reported in other current assets at December 31, 2011, to inventories to be consistent with the current year presentation on the balance sheets.

We adjusted changes in working capital on the statements of cash flows by reclassifying $(9.0) million and $(1.7) million related to materials and supplies at December 31, 2011, and 2010, respectively, from the change in other current assets line item to the change in inventories line item. We reclassified $2.9 million and $18.6 million reported in the issuance of common stock line item at December 31, 2011, and 2010, respectively, and $7.4 million and $0.2 million reported in other financing activities at December 31, 2011, and 2010, respectively, to the proceeds from stock option exercises line item. These reclassifications were made to be consistent with the current year presentation on the statements of cash flows. They had no impact on total cash flows from operating or financing activities.

(d) Use of Estimates—We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. We make estimates and assumptions that affect assets, liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(e) Cash and Cash Equivalents—Short-term investments with an original maturity of three months or less are reported as cash equivalents.

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

(Millions)	2012	2011	2010
Cash paid for interest	$109.7	$130.7	$138.7

Cash received for income taxes	(47.6)	(80.0)	(2.2)

Significant noncash transactions were:

(Millions)	2012	2011	2010
Construction costs funded through accounts payable	$92.4	$58.6	$18.3
Portion of Westwood sale financed with note receivable *	4.0	—	—
Equity issued for stock-based compensation plans	—	15.8	3.0
Equity issued for reinvested dividends	—	5.4	22.6

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

(f) Revenues and Customer Receivables—Revenues related to the sale of energy are recognized when service is provided or energy is delivered to customers. We also accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. At December 31, 2012 and 2011, our unbilled revenues were $298.2 million and $282.1 million, respectively.

At December 31, 2012, there were no customers or industries that accounted for more than 10% of our revenues.

We present revenues net of pass-through taxes on the income statements.

Our utility subsidiaries have various rate-adjustment mechanisms in place that allow subsequent adjustments to rates for changes in prudently incurred costs. A summary of significant rate-adjustment mechanisms follows:

- Fuel and purchased power costs are recovered from customers on a one-for-one basis by UPPCO, WPS's wholesale electric operations, and WPS's Michigan retail electric operations.
- WPS's Wisconsin retail electric operations use a "fuel window" mechanism to recover fuel and purchased power costs. Under the fuel window rule, a deferral is required for under or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers. Under or over-collections deferred in the current year are recovered or refunded in a future rate proceeding.
- The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs.
- The rates of PGL and NSG include riders for cost recovery of both environmental cleanup and energy conservation and management program costs.
- MERC's rates include a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as recovery of a financial incentive for meeting energy savings goals.
- The rates of PGL, NSG, and MGU include riders for cost recovery or refund of bad debts based on the difference between actual bad debt expense (as defined in the latest rate order) and the amount recovered in rates.
- The rates of MGU, NSG, PGL, UPPCO, and WPS include a decoupling mechanism. These mechanisms differ state by state and allow utilities to adjust rates going forward to recover or refund differences between actual and authorized margins. However, see Note 25, "Regulatory Environment," for more information on accounting for decoupling in 2012 at NSG and PGL.

Revenues are also impacted by other accounting policies related to PGL's natural gas hub and our utility subsidiaries' participation in the MISO market. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. WPS and UPPCO both sell and purchase power in the MISO market. If WPS or UPPCO is a net seller in a particular hour, the net amount is reported as revenue. If WPS or UPPCO is a net purchaser in a particular hour, the net amount is recorded as utility cost of fuel, natural gas, and purchased power on the income statements.

ITF accounts for revenues from construction management projects with the percentage of completion method. Revenue is measured by the percentage of costs incurred to date to the estimated total costs for each contract. This method is used because management considers total costs to be the best available measure of progress on these contracts.

See Note 1(h), "Risk Management Activities," for more information on the classification of certain unrealized gains and losses on derivative instruments in revenues.

(g) Inventories—Inventories consist of materials and supplies, natural gas in storage, liquid propane, and fossil fuels, including coal. Average cost is used to value materials and supplies, fossil fuels, liquid propane, and natural gas in storage for the regulated utilities, excluding PGL and NSG. PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 30% of total inventories at December 31, 2012, and 31% of total inventories at December 31, 2011. The estimated replacement cost of natural gas in inventory at December 31, 2012, and December 31, 2011, exceeded the LIFO cost by approximately $95.3 million and $65.7 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per dekatherm of $3.58 at December 31, 2012, and $3.06 at December 31, 2011.

Inventories at Integrys Energy Services are valued at the lower of cost or market. As a result, Integrys Energy Services recorded net write-downs of $3.4 million, $11.6 million, and $0.9 million in 2012, 2011, and 2010, respectively.

(h) Risk Management Activities—As part of our regular operations, we enter into contracts, including options, swaps, futures, forwards, and other contractual commitments, to manage market risks such as changes in commodity prices and interest rates, which are described more fully in Note 2, "Risk Management Activities." Derivative instruments at the utilities are entered into in accordance with the terms of the risk management plans approved by their respective Boards of Directors and, if applicable, by their respective regulators.

All derivatives are recognized on the balance sheets at their fair value unless they are designated as and 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. Most energy-related physical and financial derivatives at the utilities qualify for regulatory deferral. These derivatives are marked to fair value; the resulting risk management assets are offset with regulatory liabilities or decreases to regulatory assets, and risk management liabilities are offset with regulatory assets or decreases to regulatory liabilities. Management believes any gains or losses resulting from the eventual settlement of these derivative instruments will be refunded to or collected from customers in rates.

We classify unrealized gains and losses on derivative instruments that do not qualify for hedge accounting or regulatory deferral as a component of margins or operating and maintenance expense, depending on the nature of the transactions. Unrealized gains and losses on fair value hedges are recognized in current earnings, as are the changes in fair value of the hedged items. Fair value hedge ineffectiveness is recorded in revenue, operating and maintenance expense, or interest expense on the statements of income, based on the nature of the transactions. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the statements of cash flows unless the derivative contracts contain an other-than-insignificant financing element, in which case the cash flows are classified within financing activities.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On the balance sheets, cash collateral provided to others is shown separately as collateral on deposit, and cash collateral received from others is reflected in other current liabilities.

We have risk management contracts with various counterparties. We monitor credit exposure levels and the financial condition of our counterparties on a continuous basis to minimize credit risk. At December 31, 2012, we did not have risk management contracts with any one counterparty or industry that accounted for more than 10% of our total credit risk exposure.

(i) Emission Allowances—Integrys Energy Services accounts for emission allowances as intangible assets, with cash inflows and outflows related to purchases and sales of emission allowances recorded as investing activities in the statements of cash flows. The utilities account for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating the utilities' generation plants. Gains on sales of allowances at the utilities are returned to ratepayers. Losses on emission allowances at the utilities are included in the costs subject to the fuel window rules.

(j) Property, Plant, and Equipment—Utility plant is stated at cost, including any associated AFUDC and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses. The utilities record a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. The utilities charge the cost of units of property retired, sold, or otherwise disposed of, less salvage value, to accumulated depreciation.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates as approved by the applicable regulators. Annual utility composite depreciation rates are shown below. WPS received approval from the PSCW for lower depreciation rates, effective January 1, 2011.

Annual Utility Composite Depreciation Rates	2012		2011		2010	
WPS – Electric	2.87	%	2.88	%	3.05	%
WPS – Natural gas	2.21	%	2.22	%	3.28	%
UPPCO	3.31	%	3.33	%	3.18	%
MGU	2.71	%	2.73	%	3.55	%
MERC	3.07	%	3.10	%	3.08	%
PGL	3.16	%	3.18	%	3.10	%
NSG	2.43	%	2.42	%	2.35	%

The majority of nonregulated plant is stated at cost, net of impairments recorded, and includes capitalized interest. The costs of renewals, betterments, and major overhauls are capitalized as additions to plant. Nonregulated plant acquired as a result of mergers and acquisitions have been recorded at fair value. The gains or losses associated with ordinary retirements are recorded in the period of retirement. Maintenance, repair, and minor replacement costs are expensed as incurred. Depreciation is computed for the majority of the nonregulated subsidiaries' assets using the straight-line method over the assets' useful lives.

We capitalize certain costs related to software developed or obtained for internal use and amortize those costs to operating expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statements.

See Note 5, "Property, Plant, and Equipment," for details regarding our property, plant, and equipment balances.

(k) AFUDC and Capitalized Interest—Our utilities capitalize the cost of funds used for construction using a calculation that includes both internal equity and external debt components, as required by regulatory accounting. The internal equity component is accounted for as other income. The external debt component is accounted for as a decrease to interest expense.

Approximately 50% of WPS's retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. For 2012, WPS's average AFUDC retail rate was 7.71%, and its average AFUDC wholesale rate was 0.27%.

WPS's total AFUDC was as follows for the years ended December 31:

	2012	2011	2010
Allowance for equity funds used during construction	$2.6	$0.6	$0.7
Allowance for borrowed funds used during construction	0.9	0.2	0.3

The AFUDC calculation for the other utilities and IBS is determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities and IBS did not record significant AFUDC for 2012, 2011, or 2010.

Our nonregulated subsidiaries capitalize interest for construction projects. However, the nonregulated subsidiaries did not capitalize significant interest during 2012, 2011, and 2010.

(l) Regulatory Assets and Liabilities—Regulatory assets represent probable future revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in rates for future costs. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the year the determination is made. See Note 7, "Regulatory Assets and Liabilities," for more information.

(m) Asset Impairment—Goodwill and other intangible assets with indefinite lives are not amortized, but are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. For more information on our goodwill and other intangible assets, see Note 9, "Goodwill and Other Intangible Assets."

The carrying amount of tangible long-lived assets held and used is considered not recoverable if the carrying amount exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying amount over its fair value.

The carrying amount of assets held for sale is not recoverable if the carrying amount exceeds the fair value less estimated costs to sell the asset. An impairment loss is recorded for the excess of the asset’s carrying amount over the fair value, less estimated costs to sell.

The carrying amounts of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

Integrys Energy Services evaluates emission allowances for impairment by comparing the expected undiscounted future cash flows to the carrying amount. When allowances are expected to be used for generation, the allowances are grouped with the related power plant in the impairment evaluation.

(n) Retirement of Debt—Any call premiums or unamortized expenses associated with refinancing utility debt obligations are amortized consistent with regulatory treatment of those items, while gains or losses resulting from the retirement of utility debt that is not refinanced are either amortized over the remaining life of the original debt or recorded through current earnings, as authorized by our regulators. Any gains or losses resulting from the retirement of nonutility debt are recorded through current earnings.

(o) Asset Retirement Obligations—We recognize at fair value legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the liability and the associated retirement cost. See Note 13, "Asset Retirement Obligations," for more information.

(p) Income Taxes—We file a consolidated United States income tax return that includes domestic subsidiaries of which our ownership is 80% or more. We and our consolidated subsidiaries are parties to a federal and state tax allocation arrangement under which each entity determines its provision for income taxes on a stand-alone basis. In several states, combined or consolidated filings are required for certain subsidiaries doing business in that state.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. We record valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. Our regulated utilities defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

We use the deferral method of accounting for investment tax credits (ITCs). Under this method, we record the ITCs as deferred credits and amortize such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. Prior to 2012, we earned production tax credits (PTCs) on certain qualifying facilities. PTCs generally reduce the provision for income taxes in the year that electricity from the qualifying facility is generated and sold. ITCs and PTCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

In 2012, we elected to claim and subsequently received a Section 1603 Grant for WPS's Crane Creek Wind Project in lieu of the PTCs. The grant proceeds reduced the depreciable basis of the qualifying facility and will be reflected in income over a 12-year period through a reduction of depreciation and amortization expense. As a result, we no longer claim PTCs on any of our qualifying facilities.

We report interest and penalties accrued related to income taxes as a component of provision for income taxes in the income statements, as well as regulatory assets or regulatory liabilities on the balance sheets.

We record excess tax benefits from stock-based compensation awards when the actual tax benefit is realized. We follow the tax law ordering approach to determine when the tax benefit has been realized. Under this approach, the tax benefit is realized in the year it reduces taxable income. Current year stock-based compensation deductions are assumed to be used before any net operating loss carryforwards.

For more information regarding accounting for income taxes, see Note 14, "Income Taxes."

(q) Guarantees—Integrys Energy Group follows the guidance of the of the FASB ASC, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. For additional information on guarantees, see Note 16, "Guarantees."

(r) Employee Benefits —The costs of pension and other postretirement benefits are expensed over the periods during which employees render service. Our transition obligation related to other postretirement benefit plans was recognized over a 20-year period that began in 1993, and ended in 2012. In computing the expected return on plan assets, we use a market-related value of plan assets. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by WPS, while differences between actual investment returns and the expected return on plan assets are recognized over a five-year period for pension plans sponsored by IBS and PELLC. The benefit costs associated with employee benefit plans are allocated among our subsidiaries based on employees' time reporting and actuarial calculations, as applicable. Our regulators allow recovery in rates for the regulated utilities' net periodic benefit cost calculated under GAAP.

We recognize the funded status of defined benefit postretirement plans on the balance sheet, and recognize changes in the plans' funded status in the year in which the changes occur. Our nonregulated segments record changes in the funded status in other comprehensive income, and the regulated utilities record these changes in regulatory asset or liability accounts.

For additional information on our employee benefits, see Note 17, "Employee Benefit Plans."

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

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

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

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

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

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

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

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

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

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

- While forward price curves may have been based on observable information, significant assumptions may have been made regarding monthly shaping and locational basis differentials.
- Certain transactions were valued using price curves that extended beyond an observable period. Assumptions were made to extrapolate prices from the last observable period through the end of the transaction term, primarily through the use of historically settled data or correlations to other locations.

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

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

We recognize transfers between the levels of the fair value hierarchy at the value as of the end of the reporting period.

See Note 22, "Fair Value," for additional information.

(t) New Accounting Pronouncements—

Recently Issued Accounting Guidance Not Yet Effective

Accounting Standards Update (ASU) 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," was issued in February 2013. This guidance requires disclosure of amounts reclassified out of accumulated other comprehensive income by component. Significant amounts are required to be presented by the respective line items of net income or should be cross-referenced to other disclosures. These disclosures may be presented on the income statement or in the notes to the financial statements. This guidance is effective prospectively for reporting periods beginning after December 15, 2012. Adoption of this guidance will result in new disclosures in a footnote for the reporting period ending March 31, 2013.

ASU 2011-11, "Disclosures about Offsetting Assets and Liabilities," was issued in December 2011. The guidance requires enhanced disclosures about offsetting and related arrangements. ASU 2013-01, "Clarifying the Scope of

Disclosures About Offsetting Assets and Liabilities," was issued in January 2013. This guidance clarifies that the scope of ASU 2011-11 applies to certain derivatives included in the Derivatives and Hedging Topic of the FASB ASC. The guidance for both of these updates is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. Adoption of this guidance will result in new disclosures in Note 2, "Risk Management Activities," for the reporting period ending March 31, 2013.

ASU 2012-02, "Testing Indefinite-Lived Intangible Assets for Impairment," was issued in July 2012. This guidance gives companies an option to first perform a qualitative assessment to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. If a company concludes that this is the case, the fair value of the indefinite-lived intangible asset must be determined, and a quantitative impairment test is required. Otherwise, a company can bypass the quantitative impairment test. This guidance is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. Adoption of this guidance is not expected to have a significant impact on our financial statements.

NOTE 2—RISK MANAGEMENT ACTIVITIES

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

(Millions)	Balance Sheet Presentation *	December 31, 2012 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$2.5	$14.0
Natural gas contracts	Long-term	0.9	0.8
Financial transmission rights (FTRs)	Current	2.1	0.1
Petroleum product contracts	Current	0.2	—
Coal contracts	Current	0.3	4.7
Coal contracts	Long-term	2.2	4.3
Cash flow hedges			
Natural gas contracts	Current	—	0.4
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	51.7	48.5
Natural gas contracts	Long-term	11.5	7.6
Electric contracts	Current	88.6	114.2
Electric contracts	Long-term	30.7	45.7
	Current	145.4	181.9
	Long-term	45.3	58.4
Total		$190.7	$240.3

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

(Millions)	Balance Sheet Presentation (1)	December 31, 2011 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$9.1	$35.4
Natural gas contracts	Long-term	0.1	8.2
FTRs	Current	2.3	0.1
Petroleum product contracts	Current	0.1	—
Coal contract	Current	—	2.5
Coal contract	Long-term	—	4.4
Cash flow hedges			
Natural gas contracts	Current	—	0.9
Natural gas contracts	Long-term	—	0.2
Nonregulated Segments			
Nonhedge derivatives			

Natural gas contracts	Current	121.6	120.5	
Natural gas contracts	Long-term	41.9	40.5	
Electric contracts	Current	93.9	152.0	(2)
Electric contracts	Long-term	22.4	48.7	
Foreign exchange contracts	Current	0.2	0.2	
	Current	227.2	311.6	
	Long-term	64.4	102.0	
Total		$291.6	$413.6	

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

(2) Includes a $0.1 million risk management liability that was classified as held for sale at Integrys Energy Services. See Note 4, "Dispositions," for more information.

58

The following table shows our cash collateral positions:

(Millions)	December 31, 2012	December 31, 2011
Cash collateral provided to others	$41.0	$50.9
Cash collateral received from others	0.2	2.3

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

(Millions)	December 31, 2012	December 31, 2011
Integrys Energy Services	$108.9	$193.8
Utility segments	14.0	39.1

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

(Millions)	December 31, 2012	December 31, 2011
Collateral that would have been required:		
Integrys Energy Services	$173.8	$272.3
Utility segments	10.1	28.7
Collateral already satisfied:		
Integrys Energy Services – Letters of credit	3.2	11.0
Collateral remaining:		
Integrys Energy Services	170.6	261.3
Utility segments	10.1	28.7

Utility Segments

Nonhedge Derivatives

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

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

	December 31, 2012			December 31, 2011	
	Purchases	Sales	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	1,072.6	0.1	N/A	1,122.7	N/A
FTRs (millions of kilowatt-hours)	N/A	N/A	4,057.2	N/A	5,077.5
Petroleum products (barrels)	62,811.0	N/A	N/A	46,872.0	N/A
Coal contracts (millions of tons)	5.1	N/A	N/A	4.1	N/A

59

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

(Millions)	Financial Statement Presentation	2012	2011	2010
Natural gas contracts	Balance Sheet – Regulatory assets (current)	$24.6	$(11.3)	$(1.7)
Natural gas contracts	Balance Sheet – Regulatory assets (long-term)	8.3	(7.6)	0.1
Natural gas contracts	Balance Sheet – Regulatory liabilities (current)	(7.8)	8.4	—
Natural gas contracts	Balance Sheet – Regulatory liabilities (long-term)	0.3	—	—
Natural gas contracts	Income Statement – Utility cost of fuel, natural gas, and purchased power	0.2	—	—
FTRs	Balance Sheet – Regulatory assets (current)	0.1	(0.4)	1.0
FTRs	Balance Sheet – Regulatory liabilities (current)	0.1	(1.3)	(2.1)
Petroleum product contracts	Balance Sheet – Regulatory assets (current)	0.1	(0.1)	—
Petroleum product contracts	Balance Sheet – Regulatory liabilities (current)	—	—	0.1
Petroleum product contracts	Income Statement – Operating and maintenance expense	—	(0.1)	0.1
Coal contracts	Balance Sheet – Regulatory assets (current)	(2.2)	(1.3)	(1.2)
Coal contracts	Balance Sheet – Regulatory assets (long-term)	0.1	(4.4)	—
Coal contracts	Balance Sheet – Regulatory liabilities (current)	0.3	—	—
Coal contracts	Balance Sheet – Regulatory liabilities (long-term)	2.2	(3.7)	3.7

Nonregulated Segments

Nonhedge Derivatives

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

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

	December 31, 2012		December 31, 2011	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity contracts				
Natural gas (therms)	782.0	679.0	959.2	797.1
Electric (kilowatt-hours)	54,127.6	31,809.6	34,405.7	20,374.0
Foreign exchange contracts (Canadian dollars)	0.4	0.4	4.2	4.2

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

(Millions)	Income Statement Presentation	2012	2011	2010
Natural gas contracts	Nonregulated revenue	$6.8	$14.0	$30.9
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI) *	(2.0)	(2.3)	(1.6)
Electric contracts	Nonregulated revenue	(2.0)	(79.0)	(92.7)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI) *	(4.3)	(1.7)	(3.7)
Interest rate swap	Interest expense	—	—	0.4
Total		$(1.5)	$(69.0)	$(66.7)

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

In the next 12 months, pre-tax losses of $0.2 million and $3.4 million related to discontinued cash flow hedges of natural gas contracts and electric contracts, respectively, are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative customer contracts.

Fair Value Hedges

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

Cash Flow Hedges

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

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

(Millions)	Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion) 2011	2010
Natural gas contracts	$(2.3)	$(15.2)
Electric contracts	3.8	(13.6)
Interest rate swaps	—	(6.0)
Total	$1.5	$(34.8)

(Millions)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Income Statement Presentation	2012	2011	2010
Settled/Realized				
Natural gas contracts	Nonregulated revenue	$—	$(9.3)	$(16.4)
Electric contracts	Nonregulated revenue	—	4.2	(21.6)
Interest rate swaps *	Interest expense	(1.1)	(1.1)	0.2
Hedge Designation Discontinued				
Natural gas contracts	Nonregulated revenue	—	(0.3)	0.2
Electric contracts	Nonregulated revenue	—	—	(9.9)
Interest rate swaps	Interest expense	—	(0.2)	—
Total		$(1.1)	$(6.7)	$(47.5)

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

(Millions)	Gain (Loss) Recognized in Income on Derivative Instruments (Ineffective Portion and Amount Excluded from Effectiveness Testing) Income Statement Presentation	2011	2010
Natural gas contracts	Nonregulated revenue	$0.3	$(1.1)
Electric contracts	Nonregulated revenue	(0.3)	(0.5)
Total		$—	$(1.6)

NOTE 3—ACQUISITIONS

Agreement to Purchase Fox Energy Center

In September 2012, WPS entered into an agreement to acquire all of the equity interests in Fox Energy Company LLC. The purchase includes the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility located in Wisconsin, along with associated contracts. WPS currently supplies natural gas for the facility and purchases 500 megawatts of capacity and the associated energy output under a tolling arrangement.

WPS will pay $390.0 million to purchase Fox Energy Company LLC, subject to post-closing adjustments primarily related to working capital. In addition, WPS will pay $50.0 million to terminate the existing tolling arrangement immediately prior to the acquisition of the facility. The purchase will be financed initially with a combination of short-term debt and cash flow from operations. The short-term debt will be replaced later in 2013 with long-term financing.

Fox Energy Center is a dual-fuel facility, equipped to use fuel oil, but expected to run primarily on natural gas. This plant will give WPS a more balanced mix of electric generation, including coal, natural gas, hydroelectric, wind, and other renewable sources.

WPS received all of the necessary regulatory approvals for this transaction, which is expected to close by the end of March 2013.

Purchase of Compressed Natural Gas Fueling Business

On September 1, 2011, we acquired two compressed natural gas fueling businesses through our newly formed, indirect wholly owned subsidiary, ITF. The total consideration paid for the acquisition of Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) was $49.6 million. The total cash payment for this transaction was $42.6 million, which was net of cash acquired of approximately $7 million. In 2012, we received $1.3 million as a result of post-closing working capital adjustments.

Trillium and Pinnacle design, build, maintain, own and/or operate compressed natural gas fueling stations in multiple states. In addition, Pinnacle manufactures and sells a patented method to pressurize compressed natural gas.

See Note 9, "Goodwill and Other Intangible Assets," for more information related to this acquisition.

NOTE 4—DISPOSITIONS

Discontinued Operations from Holding Company and Other Segment

During 2012 and 2011, we recorded a $1.8 million after-tax gain and a $0.5 million after-tax loss, respectively, in discontinued operations at the holding company and other segment. Uncertain tax positions included in our liability for unrecognized tax benefits were remeasured to better reflect how the underlying positions are resolving themselves in various taxing jurisdictions. We also effectively settled certain state income tax examinations in 2012.

Discontinued Operations from Integrys Energy Services Segment

Potential Sale of Combined Locks Energy Center

Integrys Energy Services is currently pursuing the sale of Combined Locks Energy Center (Combined Locks), a natural gas-fired co-generation facility located in Wisconsin, as part of its long-term energy asset strategy of investing in distributed renewable projects. The sale of Combined Locks is expected to be completed within a year.

During 2010, Integrys Energy Services recorded a pre-tax impairment loss of $20.1 million ($12.1 million after tax) related to Combined Locks. The impairment charge resulted from lower estimated future cash flows and was primarily driven by forward energy and capacity prices. The impairment loss was reported in discontinued operations on the income statements.

The carrying values of the major classes of assets related to Combined Locks classified as held for sale on the balance sheets were as follows at December 31:

(Millions)	2012	2011
Inventories	$0.5	$0.4
Property, plant, and equipment, net of accumulated depreciation of $0.5 and $0.3, respectively	2.0	2.3
Total assets	$2.5	$2.7

A summary of the components of discontinued operations related to Combined Locks recorded on the income statements for 2012, 2011, and 2010 is as follows:

(Millions)	2012	2011	2010
Nonregulated revenues	$0.3	$7.9	$9.1
Nonregulated cost of sales	(0.5)	(2.0)	(2.2)
Operating and maintenance expense	(0.5)	(0.7)	(0.8)
Impairment losses	—	—	(20.1)
Depreciation and amortization expense	(0.2)	(0.3)	(1.5)
Taxes other than income taxes	(0.1)	(0.2)	(0.1)
Income (loss) before taxes	(1.0)	4.7	(15.6)
(Provision) benefit for income taxes	0.4	(1.8)	6.1
Discontinued operations, net of tax	$(0.6)	$2.9	$(9.5)

Sale of WPS Westwood Generation, LLC

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

In conjunction with the sale, Integrys Energy Services repaid $27.0 million of Refunding Tax Exempt Bonds to Schuylkill County Industrial Development Authority in November 2012. Deferred financing costs of $0.4 million were written off to the loss on sale when these bonds were repaid. The bonds were required to be repaid prior to the closing of the sale transaction because the Westwood assets were a substantial portion of the collateral on these borrowings. See Note 12, "Long-term Debt," for more information regarding this repayment.

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

(Millions)	As of the Closing Date in November 2012	As of December 31, 2011
Inventories	$1.0	$1.1
Current assets from risk management activities	0.1	—
Property, plant, and equipment, net of accumulated depreciation of $ – and $10.9, respectively	5.5	14.1
Other long-term assets	1.1	1.2
Total assets	$7.7	$16.4
Current liabilities from risk management activities	$—	$0.1
Other current liabilities	—	0.2
Long-term debt	—	27.0
Long-term liabilities from risk management activities	0.1	—
Total liabilities	$0.1	$27.3

A summary of the components of discontinued operations related to Westwood recorded on the income statements for 2012, 2011, and 2010 were as follows:

(Millions)	2012	2011	2010
Nonregulated revenues	$9.2	$12.4	$16.1
Nonregulated cost of sales	(4.4)	(5.6)	(5.5)
Operating and maintenance expense	(5.3)	(5.7)	(6.4)
Impairment losses	(8.4)	—	—
Loss on sale at closing	(0.6)	—	—
Depreciation and amortization expense	(1.0)	(1.4)	(1.4)
Taxes other than income taxes	(0.2)	(0.2)	—
Miscellaneous income	—	0.1	—
Interest expense	(0.7)	(0.6)	(1.2)
Income (loss) before taxes	(11.4)	(1.0)	1.6
(Provision) benefit for income taxes	4.5	0.3	(0.7)
Discontinued operations, net of tax	$(6.9)	$(0.7)	$0.9

Integrys Energy Services will receive interest income for seven and one-half years related to the note receivable from the buyer. The sale will also generate immaterial cash flows from providing certain administrative transition services for up to a six-month period following the sale. However, Integrys Energy Services does not have the ability to significantly influence the operating or financial policies of Westwood and also does not have significant continuing involvement in the operations of Westwood. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Westwood.

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

In October 2012, WPS Empire State, Inc, a subsidiary of Integrys Energy Services, entered into a definitive agreement to sell all of the membership interests of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse), both of which own natural gas-fired generation plants located in the state of New York. The proceeds from the sale are estimated to be $1.8 million, subject to certain post-closing adjustments primarily related to working capital. The sale agreement also includes a potential annual payment to Integrys Energy Services for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out).

Integrys Energy Services recorded a pre-tax impairment loss of $1.1 million ($0.7 million after tax) related to Beaver Falls and Syracuse during 2012 when the assets and liabilities were initially classified as held for sale. Other gains or losses may be recognized related to adjustments to selling costs at closing, as well as changes in the fair value of financial instruments included in the sale. The transaction is expected to close by the end of the first quarter of 2013.

During 2010, Integrys Energy Services recorded a pre-tax impairment loss of $23.1 million ($13.9 million after tax) related to Beaver Falls and Syracuse. The impairment charge resulted from lower estimated future cash flows for Beaver Falls and Syracuse and was primarily driven by forward energy and capacity prices. The impairment loss was reported in discontinued operations on the income statements.

The carrying values of the major classes of assets and liabilities related to Beaver Falls and Syracuse classified as held for sale on the balance sheets were as follows at December 31:

(Millions)	2012	2011
Inventories	$1.8	$2.2
Other current assets	—	0.2
Property, plant, and equipment, net of accumulated depreciation of $ – and $0.9, respectively	5.7	7.2
Other long-term assets	0.1	0.1
Total assets	$7.6	$9.7
Total liabilities – other current liabilities	$0.2	$—

A summary of the components of discontinued operations related to Beaver Falls and Syracuse recorded on the income statements for 2012, 2011, and 2010 were as follows:

(Millions)	2012	2011	2010
Nonregulated revenues	$0.6	$5.0	$9.8
Nonregulated cost of sales	(2.0)	(2.3)	(2.3)
Operating and maintenance expense	(2.4)	(3.3)	(2.6)
Impairment losses	(1.1)	—	(23.1)
Depreciation and amortization expense	(0.6)	(0.7)	(2.5)
Taxes other than income taxes	(1.4)	(0.9)	(1.1)
Miscellaneous income	0.3	—	—
Loss before taxes	(6.6)	(2.2)	(21.8)
Benefit for income taxes	2.6	0.9	8.7
Discontinued operations, net of tax	$(4.0)	$(1.3)	$(13.1)

The pending sale of Beaver Falls and Syracuse will generate immaterial cash flows from providing certain administrative transition services for up to a six-month period following the sale and from a potential four-year earn-out payment. Integrys Energy Services will also continue to satisfy certain capacity obligations and settle certain forward financial natural gas swaps under contracts that existed at the time of sale. Both of these transactions will generate cash flows that will expire within two years of the sale and are not considered significant to the overall operations of Beaver Falls and Syracuse. Additionally, Integrys Energy Services will not have the ability to significantly influence the operating or financial policies of Beaver Falls and Syracuse and will also not have significant continuing involvement in the operations of Beaver Falls and Syracuse after they are sold. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Beaver Falls and Syracuse.

Sale of Energy Management Consulting Business

During 2011 and 2010, Integrys Energy Services recorded a $0.1 million and $0.2 million after-tax gain, respectively, in discontinued operations when contingent payments were earned related to the 2009 sale of its energy management consulting business.

Dispositions Related to Integrys Energy Services Strategy Change

As part of the decision to reposition our nonregulated energy services business segment to focus on selected retail markets in the United States and investments in energy assets with renewable attributes, Integrys Energy Services completed the following sales in 2010.

Sale of Integrys Energy Services of Texas, LP

In June 2010, Integrys Energy Services sold its Texas retail electric marketing business. The pre-tax gain on the sale of Integrys Energy Services of Texas, LP was $25.5 million and was reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

Sale of Canadian Natural Gas and Wholesale Electric Marketing and Trading Portfolio

The majority of Integrys Energy Services' Canadian natural gas and electric power portfolio was sold in September 2009. In May 2010, Integrys Energy Services completed the sale of its remaining Canadian wholesale electric marketing and trading portfolio. The pre-tax loss on the sale in 2010 was $0.4 million and was reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

Sale of Renewable Energy Certificates Portfolio

In March 2010, Integrys Energy Services sold its environmental markets business, which consisted of a portfolio of long-term renewable energy certificate contracts with generators, wholesalers, municipalities, cooperatives, and large industrial companies. The pre-tax gain on the sale of the renewable energy certificate contracts was $2.8 million and was reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

Sale of United States Wholesale Electric Marketing and Trading Business

In December 2009, Integrys Energy Services entered into a definitive agreement to sell substantially all of its United States wholesale electric marketing and trading business. Effective February 1, 2010, Integrys Energy Services transferred substantially all of the market risk associated with this business by entering into trades with the buyer that mirrored Integrys Energy Services' underlying wholesale electric contracts. In March 2010, Integrys Energy Services closed on the sale and transferred title to the majority of the underlying commodity contracts, at which time the corresponding mirror transactions terminated.

In conjunction with the sale, Integrys Energy Services entered into derivative contracts with the buyer to re-establish the economic hedges for the retained United States retail electric business, with the same prices and terms originally executed through Integrys Energy Services' United States wholesale electric marketing and trading business. Integrys Energy Services retained counterparty default risk with approximately 50% of the counterparties to the commodity contracts novated, all of which had expired as of December 31, 2012.

Integrys Energy Services closed on the sale of its only remaining significant wholesale electric commodity contract with another buyer in March 2010.

The pre-tax loss on the sale of the United States wholesale electric marketing and trading business and the remaining commodity contract, net of the gain resulting from the fair value adjustment for the default risk, was $55.7 million in 2010. The 2011 gain due to the change in the carrying value of the default risk was insignificant, as the majority of these contracts ended in 2011. The pre-tax gains and losses for both years were reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

Sale of Generation Businesses in New Brunswick, Canada and Northern Maine, and Associated Retail Electric Contracts

In January 2010, Integrys Energy Services closed on the sale of two of its power generation businesses, which owned generation assets in New Brunswick, Canada and northern Maine, and subsequently closed on the sale of the associated retail electric contracts and standard offer service contracts in northern Maine in February 2010. In conjunction with the sale, Integrys Energy Services entered into derivative contracts with the buyer of the northern Maine retail electric sales contracts to offset the retained economic hedges associated with the customer contracts sold. The proceeds from the sale of the generation companies and associated retail electric contracts were $38.5 million. The pre-tax gain on the sales was $15.7 million and was reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

Sale of United States Wholesale Natural Gas Marketing and Trading Business and Other Wholesale Natural Gas Storage Contracts

In October 2009, Integrys Energy Services entered into definitive agreements to sell the majority of its United States wholesale natural gas marketing and trading business in a two-part transaction. In December 2009, Integrys Energy

Services closed the first part of the transaction by selling substantially all of its United States wholesale natural gas marketing and trading business. The second part of the transaction included the sale of its remaining natural gas storage and related transportation contracts through multiple transactions which closed during the first half of 2010. In January 2010, the buyer exercised its option to purchase these wholesale natural gas storage and related transportation contracts.

The pre-tax loss on the sale of the United States wholesale natural gas marketing and trading business and natural gas storage and related transportation contracts as of 2010 was $2.0 million and was reported as a component of net (gain) loss on Integrys Energy Services' dispositions related to strategy change on the income statement.

NOTE 5—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility, nonutility, and nonregulated assets at December 31:

(Millions)	2012	2011
Electric utility	$3,095.8	$3,139.7
Natural gas utility	5,050.8	4,751.4
Total utility plant	8,146.6	7,891.1
Less: Accumulated depreciation	3,006.1	2,910.1
Net	5,140.5	4,981.0
Construction work in progress	203.1	62.0
Net utility plant	5,343.6	5,043.0
Nonutility plant	120.2	130.4
Less: Accumulated depreciation	72.3	68.7
Net	47.9	61.7
Construction work in progress	19.6	2.7
Net nonutility plant	67.5	64.4
Integrys Energy Services energy assets	92.0	64.9
Integrys Energy Services other	17.9	20.0
Other nonregulated	14.0	8.0
Total nonregulated property, plant, and equipment	123.9	92.9
Less: Accumulated depreciation	36.3	27.8
Net	87.6	65.1
Construction work in progress	3.2	3.0
Net nonregulated property, plant, and equipment	90.8	68.1
Total property, plant, and equipment	$5,501.9	$5,175.5

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist. During 2011, Integrys Energy Services recorded a pre-tax noncash impairment loss of $4.6 million related to its Winnebago Energy Center, a landfill-gas-to-electric facility. The impairment charge resulted from lower estimated future cash flows and was primarily driven by forward energy and capacity prices. The impairment charge was reported as part of operating and maintenance expense in the income statements. The fair value of the facility was determined primarily using the income approach, which was based on discounted cash flows that were derived from internal forecasts. These forecasts considered externally supplied forward energy and capacity pricing curves as well as renewable energy credits. Other assumptions included forecasted operating expenses, forecasted capital additions, anticipated working capital requirements, and the discount rate. The 7.5% discount rate used represents the estimated cost of capital for the facility and was also based upon the cash flow period used for the fair value assessment.

See Note 4, "Dispositions," for additional impairment losses recorded in discontinued operations at Integrys Energy Services during the years ended December 31, 2012 and 2010. The impairments were recorded on property and equipment either sold during 2012 or presented in the balance sheets as assets held for sale.

NOTE 6—JOINTLY OWNED UTILITY FACILITIES

WPS holds a joint ownership interest in certain electric generating facilities. WPS is entitled to its share of generating capability and output of each facility equal to its respective ownership interest. WPS also pays its ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit its maximum exposure to additional costs. WPS records its proportionate share of significant jointly owned electric generating facilities on the balance sheets. The amounts were as follows at December 31, 2012:

(Millions, except for percentages and megawatts)	Weston 4	Columbia Energy Center Units 1 and 2	Edgewater Unit 4
Ownership	70.0 %	31.8 %	31.8 %
WPS's share of rated capacity (megawatts)	374.5	335.2	105.0
In-service date	2008	1975 and 1978	1969
Utility plant	$576.3	$170.0	$41.2
Accumulated depreciation	$(97.0)	$(109.1)	$(26.7)
Construction work in progress	$1.0	$91.0	$0.3

WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. WPS has supplied its own financing for all jointly owned projects.

NOTE 7—REGULATORY ASSETS AND LIABILITIES

Our utility subsidiaries expect to recover their regulatory assets and incur future costs or refund their regulatory liabilities through rates charged to customers. Recovery or refund is based on specific periods determined by the regulators or over the normal operating period of the assets and liabilities to which they relate. Based on prior and current rate treatment, we believe it is probable that our utility subsidiaries will continue to recover from customers the regulatory assets described below.

The following regulatory assets and liabilities were reflected on our balance sheets as of December 31:

(Millions)	2012	2011	See Note
Regulatory assets [1]			
Unrecognized pension and other postretirement benefit costs [2]	$810.0	$733.6	17
Environmental remediation costs (net of insurance recoveries) [3]	689.7	626.8	15
Merger and acquisition related pension and other postretirement benefit costs [4]	110.1	121.9	
Asset retirement obligations	73.9	58.1	13
Income tax related items	47.6	37.9	14
Crane Creek production tax credits [5]	34.9	—	
Derivatives	30.7	59.0	1(h)
De Pere Energy Center [6]	26.2	28.6	
Unamortized loss on reacquired debt [7]	18.2	18.8	1(n)
Energy costs receivable through rate adjustments [8]	18.1	7.4	
Energy efficiency programs [9]	16.7	13.3	
Decoupling	10.6	33.3	25
Other	37.9	44.9	
Total	$1,924.6	$1,783.6	
Balance Sheet Presentation			
Current	$110.8	$125.1	
Long-term	1,813.8	1,658.5	
Total	$1,924.6	$1,783.6	
Regulatory liabilities			
Removal costs [10]	$318.4	$298.0	
Energy costs refundable through rate adjustments [8]	44.4	30.4	
Unrecognized pension and other postretirement benefit costs	17.7	18.4	17
Decoupling	15.9	17.2	25
Uncollectible expense	10.0	11.3	25
Crane Creek depreciation deferral [5]	9.4	—	
Energy efficiency programs [9]	8.8	5.4	
Derivatives	4.3	9.3	1(h)
Other	7.2	10.0	
Total	$436.1	$400.0	
Balance Sheet Presentation			
Current	$65.6	$67.5	
Long-term	370.5	332.5	
Total	$436.1	$400.0	

(1)

The following regulatory assets are not earning a return: unrecognized pension and other postretirement benefit costs at PGL and NSG; environmental remediation costs at WPS and UPPCO; merger and acquisition related pension and other postretirement benefit costs; WPS energy costs receivable through rate adjustments; and decoupling at MERC, MGU, and UPPCO.

(2) Represents the unrecognized future pension and postretirement costs resulting from actuarial gains and losses on Integrys Energy Group's defined benefit and postretirement plans. We are authorized recovery of this regulatory asset over the average future remaining service life of each plan.

(3) As of December 31, 2012, we had not yet made cash expenditures for $651.5 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(4) Composed of unrecognized benefit costs that existed prior to the PELLC merger and the MERC and MGU acquisitions. MERC and MGU are authorized recovery of this regulatory asset through 2026. PGL and NSG are authorized recovery of the pension portion of this regulatory asset through 2023, and through 2019 for the portion related to other postretirement benefit costs.

(5) In 2012, we elected to claim and subsequently received a Section 1603 grant for our Crane Creek wind project in lieu of the production tax credit. As a result, we reversed previously recorded production tax credits. We also reduced the depreciable basis of the qualifying facility by the amount of the grant proceeds, which will result in a reduction of depreciation and amortization expense over a 12-year period. We recorded a regulatory asset for the deferral of previously recorded production tax credits, partially offset by a regulatory liability related to a portion of the book depreciation taken in prior years. WPS is authorized recovery of this net regulatory asset through 2039.

(6) Prior to WPS purchasing the De Pere Energy Center in 2002, WPS had a long-term power purchase contract with the De Pere Energy Center that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. WPS is authorized recovery of this regulatory asset through 2023.

(7) Amounts are recovered over the term of the replacement debt as authorized by the various commissions.

(8) Represents the under or over-collection of energy costs that will be recovered from or refunded to customers in the future.

(9) Represents amounts recoverable from and/or refundable to customers related to programs at MERC, NSG, PGL and WPS designed to meet energy efficiency standards. WPS is authorized recovery of this regulatory asset through 2013.

(10) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.

NOTE 8—EQUITY METHOD INVESTMENTS

Investments in corporate joint ventures and other companies accounted for under the equity method at December 31, 2012, and 2011 were as follows:

(Millions)	2012	2011
ATC	$476.6	$439.4
INDU Solar Holdings, LLC	27.5	28.4
WRPC	7.3	7.7
Other	0.8	0.8
Equity method investments	$512.2	$476.3

ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at December 31, 2012. ATC is a for-profit, transmission-only company regulated by FERC. ATC owns, maintains, monitors, and operates electric transmission assets in portions of Wisconsin, Michigan, Minnesota, and Illinois.

The following table shows changes to our investment in ATC during the years ended December 31:

(Millions)	2012	2011	2010
Balance at the beginning of period	$439.4	$416.3	$395.9
Add: Earnings from equity method investment	85.3	79.1	77.6
Add: Capital contributions	20.4	8.5	6.8
Less: Dividends received	68.5	64.5	64.0
Balance at the end of period	$476.6	$439.4	$416.3

The regulated electric utilities provide construction and other services to ATC and receive network transmission services from ATC. The related party transactions recorded by the regulated electric utilities during the years ended December 31 were as follows:

(Millions)	2012	2011	2010
Total charges to ATC for services and construction	$12.5	$13.5	$14.0

Total costs for network transmission service provided by ATC	100.3	102.7	103.0

INDU Solar Holdings, LLC

Integrys Solar, LLC, a subsidiary of Integrys Energy Services, owns 50% of INDU Solar Holdings, LLC. INDU Solar Holdings, LLC owns solar energy projects in California, Pennsylvania, New Jersey, Arizona, and Massachusetts that deliver electricity and related products to commercial, government, and utility customers under long-term power purchase agreements.

The following table shows changes to our investment in INDU Solar Holdings, LLC during the years ended December 31:

(Millions)	2012	2011
Balance at the beginning of period	$28.4	$0.1
Add: Earnings (loss) from equity method investment	1.1	(0.7)
Add: Capital contributions	7.0	29.0
Less: Return of capital to partners	9.0	—
Balance at the end of period	$27.5	$28.4

WRPC

WPS owns 50% of the stock of WRPC, which operates two hydroelectric plants and an oil-fired combustion turbine. Two-thirds of the energy output of the hydroelectric plants is sold to WPS, and the remaining one-third is sold to Wisconsin Power and Light. The electric power from the combustion turbine is sold in equal parts to WPS and Wisconsin Power and Light.

The following table shows changes to our investment in WRPC during the years ended December 31:

(Millions)	2012	2011	2010
Balance at the beginning of period	$7.7	$8.1	$8.5
Add: Earnings from equity method investment	0.8	0.9	1.0
Less: Dividends received	1.2	1.3	1.4
Balance at the end of period	$7.3	$7.7	$8.1

WPS provides services to WRPC, purchases energy from WRPC, and receives net proceeds from sales of energy into the MISO market from WRPC. The related party transactions recorded by WPS during the years ended December 31 were as follows:

(Millions)	2012	2011	2010
Revenues from services provided to WRPC	$0.8	$0.7	$0.6
Purchases of energy from WRPC	5.0	4.9	4.7
Net proceeds from WRPC sales of energy to MISO	2.9	4.7	4.5

Financial Data

Combined financial data of our significant equity method investments, ATC, INDU Solar Holdings, LLC, and WRPC, is included in the table below:

(Millions)	2012	2011	2010
Income statement data			
Revenues	$618.3	$575.5	$564.1
Operating expenses	292.1	269.6	257.6
Other expense	85.1	81.5	85.7
Net income	$241.1	$224.4	$220.8
Earnings from equity method investments	$87.2	$79.4	$78.2
Balance sheet data			
Current assets	$81.1	$91.1	$62.7
Noncurrent assets	3,347.4	3,120.5	2,906.2
Total assets	$3,428.5	$3,211.6	$2,968.9
Current liabilities	$253.0	$319.9	$429.0
Long-term debt	1,559.5	1,400.0	1,175.0
Other noncurrent liabilities	103.5	88.0	88.5
Shareholders' equity	1,512.5	1,403.7	1,276.4
Total liabilities and shareholders' equity	$3,428.5	$3,211.6	$2,968.9

NOTE 9—GOODWILL AND OTHER INTANGIBLE ASSETS

We had the following changes in the gross amount of goodwill and the accumulated impairment losses for the years ended December 31, 2012 and 2011:

	Natural Gas Segment		Integrys Energy Services		Holding Company and Other		Total	
(Millions)	2012	2011	2012	2011	2012	2011	2012	2011
Balance as of January 1								
Gross goodwill	$933.5	$933.5	$6.6	$6.6	$15.9	$—	$956.0	$940.1
Accumulated impairment losses	(297.6)	(297.6)	—	—	—	—	(297.6)	(297.6)
Net goodwill	635.9	635.9	6.6	6.6	15.9	—	658.4	642.5
Goodwill acquired	—	—	—	—	—	15.9	—	15.9
Adjustment to Trillium and Pinnacle purchase price	—	—	—	—	(0.1)	—	(0.1)	—
Balance as of December 31								
Gross goodwill	933.5	933.5	6.6	6.6	15.8	15.9	955.9	956.0
Accumulated impairment losses	(297.6)	(297.6)	—	—	—	—	(297.6)	(297.6)
Net goodwill	$635.9	$635.9	$6.6	$6.6	$15.8	$15.9	$658.3	$658.4

In the second quarter of 2012, annual impairment tests were completed at all of our reporting units that carried a goodwill balance. No impairments resulted from these tests.

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

	December 31, 2012			December 31, 2011		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Customer-related (1)	$22.4	$ (14.7)	$7.7	$34.5	$ (24.8)	$9.7
Electric contract assets (2)	—	—	—	7.8	(6.6)	1.2
Patents (3)	7.2	(0.3)	6.9	7.2	—	7.2
Compressed natural gas fueling contract assets (4)	5.6	(1.3)	4.3	5.6	(0.3)	5.3
Renewable energy credits (5)	3.1	—	3.1	2.8	—	2.8
Nonregulated easements (6)	3.8	(0.9)	2.9	3.8	(0.7)	3.1
Customer-owned equipment modifications (7)	4.0	(0.5)	3.5	3.6	(0.2)	3.4
Emission allowances (8)	—	—	—	1.7	(0.2)	1.5
Other	0.5	(0.2)	0.3	1.4	(0.3)	1.1
Total	$46.6	$ (17.9)	$28.7	$68.4	$ (33.1)	$35.3
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name	1.5	—	1.5	1.5	—	1.5

Total intangible assets	$56.8	$ (17.9)	$38.9	$78.6	$ (33.1)	$45.5

(1) Represents customer relationship assets associated with PELLC's former nonregulated retail natural gas and electric operations, MERC's nonutility ServiceChoice business, and Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at December 31, 2012, was approximately 9 years.

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

(3) Represents the fair value of patents at Pinnacle related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at December 31, 2012, was approximately 17 years.

(4) Represents the fair value of Trillium and Pinnacle contracts acquired in September 2011. The remaining amortization period at December 31, 2012, was approximately 8 years.

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

(6) Relates to easements supporting a pipeline at Integrys Energy Services. The easements are amortized on a straight-line basis, with a remaining amortization period at December 31, 2012, of approximately 11 years.

(7) Relates to modifications by Integrys Energy Services and Trillium to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted average amortization period at December 31, 2012, of approximately 11 years.

(8) Emission allowances do not have a contractual term or expiration date.

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income for the years ended December 31, 2012, 2011, and 2010, was $2.5 million, $1.3 million, and $4.7 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the years ended December 31, 2012, 2011, and 2010, was $2.5 million, $3.4 million, and $3.9 million, respectively.

An insignificant amount of amortization expense was recorded in discontinued operations for the years ended December 31, 2012, 2011, and 2010.

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

	For the year ending December 31				
(Millions)	2013	2014	2015	2016	2017
Amortization to be recorded in nonregulated cost of sales	$4.7	$1.2	$1.1	$0.9	$0.9
Amortization to be recorded in depreciation and amortization expense	2.0	1.8	1.7	1.5	1.4

NOTE 10—LEASES

We lease various property, plant, and equipment. Terms of the operating leases vary, but generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value or (b) exercise a renewal option, as set forth in the lease agreement. Rental expense attributable to operating leases was $12.4 million, $12.6 million, and $15.2 million in 2012, 2011, and 2010, respectively. Future minimum rental obligations under noncancelable operating leases are payable as follows:

Year ending December 31 (Millions)	Payments
2013	$8.5
2014	5.3
2015	4.7
2016	4.7
2017	5.8
Later years	60.3
Total	$89.3

NOTE 11—SHORT-TERM DEBT AND LINES OF CREDIT

Our outstanding short-term borrowings were as follows as of December 31:

(Millions, except percentages)	2012	2011	2010

Commercial paper outstanding	$482.4	$303.3	—
Average discount rate on outstanding commercial paper	0.40%	0.31%	—
Short-term notes payable outstanding	—	—	$10.0
Average interest rate on short-term notes payable outstanding	—	—	0.32%

The commercial paper outstanding at December 31, 2012, had maturity dates ranging from January 2, 2013 through January 22, 2013.

The table below presents our average amount of short-term borrowings based on daily outstanding balances during the years ended December 31:

(Millions)	2012	2011	2010
Average amount of commercial paper	$326.3	$134.9	$66.9
Average amount of short-term notes payable	—	3.6	10.0

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities, as of December 31:

(Millions)	Maturity	2012	2011
Revolving credit facility (Integrys Energy Group) [(1)]	04/23/2013	$—	$735.0
Revolving credit facility (Integrys Energy Group)	05/17/2014	275.0	275.0
Revolving credit facility (Integrys Energy Group)	05/17/2016	200.0	200.0
Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	—
Revolving credit facility (WPS) [(1)]	04/23/2013	—	115.0
Revolving credit facility (WPS) [(2)]	06/12/2013	115.0	—
Revolving credit facility (WPS)	05/17/2014	135.0	135.0
Revolving credit facility (PGL) [(1)]	04/23/2013	—	250.0
Revolving credit facility (PGL)	06/13/2017	250.0	—
Total short-term credit capacity		$1,610.0	$1,710.0
Less:			
Letters of credit issued inside credit facilities		$25.5	$33.7
Commercial paper outstanding		482.4	303.3
Available capacity under existing agreements		$1,102.1	$1,373.0

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

(2) This facility will automatically extend through June 13, 2017, upon PSCW approval, which is expected prior to June 13, 2013.

In connection with the pending purchase of Fox Energy Company LLC, WPS requested approval from the PSCW to temporarily increase its short-term debt limit. See Note 3, “Acquisitions,” for more information regarding this pending purchase.

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 nonrecourse debt. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations. At December 31, 2012, we and each of our subsidiaries were in compliance with all respective covenants related to outstanding short-term debt.

NOTE 12—LONG-TERM DEBT

(Millions)				December 31 2012	2011
WPS First Mortgage Bonds [1]					
	Series	Year Due			
	7.125%	2023		$0.1	$0.1
WPS Senior Notes [1] [2]					
	Series	Year Due			
	4.875%	2012		—	150.0
	4.80%	2013		125.0	125.0
	3.95%	2013		22.0	22.0
	6.375%	2015		125.0	125.0
	5.65%	2017		125.0	125.0
	6.08%	2028		50.0	50.0
	5.55%	2036		125.0	125.0
	3.671%	2042		300.0	—
PGL First and Refunding Mortgage Bonds [3]					
	Series	Year Due			
	KK, 5.00%	2033		50.0	50.0
	NN-2, 4.625%	2013		75.0	75.0
	QQ, 4.875%	2038	Adjustable after November 1, 2018	75.0	75.0
	RR, 4.30%	2035	Adjustable after June 1, 2016	50.0	50.0
	SS, 7.00%	2013		45.0	45.0
	TT, 8.00%	2018		5.0	5.0
	UU, 4.63%	2019		75.0	75.0
	VV, 2.125%	2030	Mandatory interest reset date on July 1, 2014	50.0	50.0
	WW, 2.625%	2033	Mandatory interest reset date on August 1, 2015	50.0	50.0
	XX, 2.21%	2016		50.0	50.0
	YY, 3.98%	2042		100.0	—
NSG First Mortgage Bonds [4]					
	Series	Year Due			
	M, 5.00%	2028		—	28.2
	N-2, 4.625%	2013		40.0	40.0
	O, 7.00%	2013		6.5	6.5
	P, 3.43%	2027		28.0	—
Integrys Energy Group Unsecured Senior Notes [5]					

	Series	Year Due		
	5.375%	2012	—	100.0
	7.27%	2014	100.0	100.0
	8.00%	2016	55.0	55.0
	4.17%	2020	250.0	250.0
Integrys Energy Group Unsecured Junior Subordinated Notes [6]				
	Series	Year Due		
	6.11%	2066	269.8	269.8
Other term loan [7]			—	27.0
Total			2,246.4	2,123.6
Unamortized discount on debt			(1.2)	(1.6)
Total debt			2,245.2	2,122.0
Less current portion			(313.5)	(250.0)
Less long-term debt held for sale [7]			—	(27.0)
Total long-term debt			$1,931.7	$1,845.0

(1) WPS's First Mortgage Bonds and Senior Notes are subject to the terms and conditions of WPS's First Mortgage Indenture. Under the terms of the Indenture, substantially all property owned by WPS is pledged as collateral for these outstanding debt securities. All of these debt securities require semi-annual payments of interest. WPS Senior Notes become noncollateralized if WPS retires all of its outstanding First Mortgage Bonds and no new mortgage indenture is put in place.

73

(2) In December 2012, WPS’s $150.0 million of 4.875% Senior Notes matured, and the outstanding principal balance was repaid.

In the same month, WPS issued $300.0 million of 3.671% Senior Notes. These notes are due in December 2042.

In February 2013, WPS’s 3.95% Senior Notes matured, and the outstanding principal balance was repaid. As a result, the $22.0 million balance of these notes was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

In December 2013, WPS’s 4.80% Senior Notes will mature. As a result, the $125.0 million balance of these notes was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

(3) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority and the City of Chicago have issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued equal principal amounts of certain collateralized First Mortgage Bonds.

In December 2012, PGL issued $100.0 million of 3.98% Series YY First and Refunding Mortgage Bonds. These bonds are due in December 2042.

In May 2013, PGL’s 4.625% Series NN-2 First and Refunding Mortgage Bonds will mature. As a result, the $75.0 million balance of these bonds was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

In November 2013, PGL’s 7.00% Series SS First and Refunding Mortgage Bonds will mature. As a result, the $45.0 million balance of these bonds was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

(4) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

NSG has used First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to NSG. In return, NSG issued equal principal amounts of certain collateralized First Mortgage Bonds.

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

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

In May 2013, NSG’s 4.625% Series N-2 First Mortgage Bonds will mature. As a result, the $40.0 million balance of these bonds was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

In November 2013, NSG's 7.00% Series O First Mortgage Bonds will mature. As a result, the $6.5 million balance of these bonds was included in the current portion of long-term debt on our December 31, 2012 balance sheet.

(5) In December 2012, our $100.0 million of 5.375% Unsecured Senior Notes matured, and the outstanding principal balance was repaid.

(6) These Junior Subordinated Notes are considered hybrid instruments with a combination of debt and equity characteristics. Under a replacement capital covenant with the holders of our 4.17% Unsecured Senior Notes due November 1, 2020, prior to December 1, 2036 any amounts redeemed or repurchased in excess of 10% of the principal amount outstanding must first be replaced with a specified amount of proceeds from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Subordinated Notes.

(7) WPS Westwood Generation, LLC, a subsidiary of Integrys Energy Services, repaid this loan in November 2012 in conjunction with the sale of WPS Westwood Generation, LLC. As a result, the $27.0 million balance of this loan was included in liabilities held for sale on our December 31, 2011 balance sheet. See Note 4, "Dispositions," for more information regarding the sale.

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. At December 31, 2012, we and each of our subsidiaries were in compliance with all respective covenants related to outstanding long-term debt.

A schedule of all principal debt payment amounts related to bond maturities is as follows:

(Millions)	Payments
2013	$313.5
2014	100.0
2015	125.0
2016	374.8
2017	125.0
Later years	1,208.1
Total	$2,246.4

NOTE 13—ASSET RETIREMENT OBLIGATIONS

The utility segments have asset retirement obligations primarily related to removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation facilities, office buildings, and service centers; dismantling wind generation projects; disposal of PCB-contaminated transformers; closure of fly-ash landfills at certain generation facilities; and removal of above ground storage tanks. The utilities establish regulatory assets and liabilities to record the differences between ongoing expense recognition under the asset retirement obligation accounting rules, and the ratemaking practices for retirement costs authorized by the applicable regulators. Integrys Energy Services has asset retirement obligations related to the removal of solar equipment components.

The following table shows changes to our asset retirement obligations through December 31, 2012:

(Millions)	Utilities	Integrys Energy Services	Total
Asset retirement obligations at December 31, 2009	$194.8	$0.3	$195.1
Accretion	11.7	—	11.7
Asset retirement obligations transferred in sale	—	(0.3)	(0.3)
Additions and revisions to estimated cash flows	120.5 [1]	—	120.5
Settlements	(6.1)	—	(6.1)
Asset retirement obligations at December 31, 2010	320.9	—	320.9
Accretion	17.1	—	17.1
Additions and revisions to estimated cash flows	64.4 [2]	0.5	64.9
Settlements	(5.7)	—	(5.7)
Asset retirement obligations at December 31, 2011	396.7	0.5	397.2
Accretion	20.3	0.1	20.4
Additions and revisions to estimated cash flows	(2.4)	1.6	(0.8)
Settlements	(5.6)	—	(5.6)
Asset retirement obligations at December 31, 2012	$409.0	$2.2	$411.2

(1) Revisions were made to estimated cash flows related to asset retirement obligations for natural gas distribution pipes at PGL due to changes in the average remaining service life of distribution pipe based on an updated depreciation study, as well as an increase in estimated costs.

(2) Revisions were made to estimated cash flows related to asset retirement obligations primarily due to an increase in the weighted average cost to retire a foot of natural gas distribution pipe at PGL.

NOTE 14—INCOME TAXES

Deferred Income Tax Assets and Liabilities

The principal components of deferred income tax assets and liabilities recognized on the balance sheets as of December 31 are included in the table below. Certain temporary differences are netted in the table when the offsetting amount is recorded as a regulatory asset or liability. This is consistent with regulatory treatment.

(Millions)	2012	2011
Deferred income tax assets		
Tax credit carryforwards	$105.1	$97.6
Price risk management	59.6	70.0
Other	76.5	57.6

Total deferred income tax assets	$241.2	$225.2
Valuation allowance	(7.2)	(8.0)
Net deferred income tax assets	$234.0	$217.2
Deferred income tax liabilities		
Plant-related	$1,215.7	$1,103.0
Regulatory deferrals	60.8	43.4
Other	97.0	47.3
Total deferred income tax liabilities	$1,373.5	$1,193.7
Total net deferred income tax liabilities	$1,139.5	$976.5
Balance Sheet presentation		
Current deferred income tax assets	$64.3	$94.2
Long-term deferred income tax liabilities	1,203.8	1,070.7
Net deferred income tax liabilities	$1,139.5	$976.5

Net deferred income tax liabilities increased $163.0 million in 2012. The net increase was driven by an increase in capital expenditures primarily related to the AMRP project at PGL and 50% bonus tax depreciation available in 2012. Deferred income tax liabilities also increased due to our election in 2012 to claim a Section 1603 Grant for our Crane Creek Wind Project in lieu of the production tax credit. See Note 1(p), "Income Taxes," for more information. An increase in tax deductions resulting from incremental contributions to our various employee benefit plans also contributed to the increase in net deferred income tax liabilities.

Deferred tax credit carryforwards at December 31, 2012, included $73.5 million of alternative minimum tax credits, which can be carried forward indefinitely. Other deferred tax credit carryforwards included $14.5 million of general business credits, which have a carryback period of 1 year and a carryforward period of 20 years. The majority of the general business credit carryforwards will expire in 2026. Deferred tax credit carryforwards also include $15.1 million of foreign tax credits, which have a carryforward period of 10 years. The majority of the foreign tax credit carryforwards will expire in 2020. We also have $2.0 million of deferred state tax credit carryforwards, which have a carryforward period of 5 years. The majority of the state tax credit carryforwards will expire in 2017.

At December 31, 2012, we had deferred income tax assets of $8.5 million reflecting federal operating loss carryforwards, which have a carryback period of 2 years and a carryforward period of 20 years. We also had deferred income tax assets of $15.0 million reflecting state operating loss carryforwards. The majority of the state operating loss carryforwards relate to Wisconsin and have a carryforward period of 20 years. Any deferred tax assets that are not used to offset future taxable income will expire between 2019 and 2032 as follows:

2019 through 2024	$2.4 million
2025 through 2030	$3.2 million
2031 through 2032	$17.9 million

Valuation allowances are established for certain state operating losses and foreign tax credits based on our projected ability to realize these benefits by offsetting future taxable income. Realization is dependent on generating sufficient taxable income prior to expiration. As of December 31, 2012, the entire valuation allowance was related to noncurrent deferred income tax assets. There was no significant change in the valuation allowance during 2012.

Regulated utilities record certain adjustments related to deferred income taxes to regulatory assets and liabilities. As the related temporary differences reverse, the regulated utilities prospectively refund taxes to or collect taxes from customers related to both deferred taxes recorded in prior years at rates potentially different than current rates and when there are other changes in tax laws. The net regulatory asset for these net recoveries and other regulatory tax effects totaled $42.1 million and $31.2 million at December 31, 2012, and 2011, respectively. See Note 7, "Regulatory Assets and Liabilities," for more information.

Income Before Taxes

Income before taxes includes the following components of foreign and domestic income:

	For the Years Ended December 31		
(Millions)	2012	2011	2010
Domestic	$443.9	$363.4	$396.9
Foreign	(0.1)	(0.1)	10.6
Total income before taxes	$443.8	$363.3	$407.5

76

Provision for Income Taxes

The components of the provision for income taxes were as follows:

(Millions)	2012	2011	2010
Current provision			
Federal	$3.5	$(44.2)	$(85.5)
State	0.4	6.0	(11.3)
Foreign	(0.1)	(0.2)	6.8
Total current provision	3.8	(38.4)	(90.0)
Deferred provision			
Federal	128.3	158.7	230.8
State	20.1	14.6	27.1
Foreign	—	0.1	(3.8)
Total deferred provision	148.4	173.4	254.1
Investment tax credits, net	5.2	(1.1)	(0.9)
Penalties	(0.3)	0.7	—
Unrecognized tax benefits	(3.0)	0.9	(0.6)
Interest	(4.3)	(2.2)	(0.3)
Total provision for income taxes related to continuing operations	149.8	133.3	162.3
Total provision for income taxes related to discontinued operations	(9.3)	1.1	(13.9)
Total	$140.5	$134.4	$148.4

Statutory Rate Reconciliation

The following table presents a reconciliation of the difference between the effective tax rate and the amount computed by applying the statutory federal tax rate to income before taxes.

	2012		2011		2010	
(Millions, except for percentages)	Rate	Amount	Rate	Amount	Rate	Amount
Statutory federal income tax	35.0 %	$155.4	35.0 %	$127.2	35.0 %	$142.6
State income taxes, net	4.8	21.1	5.3	19.1	5.1	20.6
Unrecognized tax benefits and interest	(1.6)	(7.3)	0.2	0.6	(0.2)	(0.9)
Federal tax credits	(1.7)	(7.6)	(2.0)	(7.1)	(1.6)	(6.7)
Benefits and compensation	(2.1)	(9.4)	(2.3)	(8.4)	1.2	5.0
Other differences, net	(0.6)	(2.4)	0.5	1.9	0.3	1.7
Effective income tax	33.8 %	$149.8	36.7 %	$133.3	39.8 %	$162.3

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(Millions)	2012	2011	2010
Balance at January 1	$22.4	$30.4	$31.8
Increase related to tax positions taken in prior years	0.9	3.1	9.2
Decrease related to tax positions taken in prior years	(6.7)	(1.6)	(10.6)
Increase related to tax positions taken in current year	0.6	0.9	—
Decrease related to settlements	(5.7)	(9.4)	—

Decrease related to lapse of statutes	(0.2)	(1.0)	—
Balance at December 31	$11.3	$22.4	$30.4

We had accrued interest of $2.5 million and accrued penalties of $2.0 million related to unrecognized tax benefits at December 31, 2012. We had accrued interest of $5.0 million and accrued penalties of $3.6 million related to unrecognized tax benefits at December 31, 2011.

Our effective tax rate could be affected by recognition of $1.9 million of unrecognized tax benefits related to continuing operations in periods after December 31, 2012. Also, our provision for income taxes could be affected by recognition of $5.2 million of unrecognized tax benefits related to discontinued operations in periods after December 31, 2012.

Our subsidiaries file income tax returns in the United States federal jurisdiction, in various state and local jurisdictions, and in Canada.

With a few exceptions, we are no longer subject to federal income tax examinations by the IRS for years prior to 2009. During 2012, the IRS continued its examinations of 2009 and 2010, which began in 2011.

We file state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. With a few exceptions, we are no longer subject to state and local tax examinations for years prior to 2005. As of December 31, 2012, we were subject to examination by state or local tax authorities for the 2005 through 2011 tax years in our major state operating jurisdictions as follows:

State	Year
Illinois	2007
Michigan	2008
Minnesota	2005
Wisconsin	2008

During 2012, examinations related only to Integrys Energy Services were completed in Wisconsin for the 2007 and 2008 tax years, which had no impact on the liability for unrecognized tax benefits. During 2012, the Illinois taxing authority continued its examination of the 2007 tax year, which began in 2010. Subsequent to December 31, 2012, we received a Notice of Audit Closure for the examination of the 2007 tax year. The effective settlement of this examination in 2013 will result in an adjustment to the provision for income taxes, of which a large portion will be reported as discontinued operations. During 2012, we effectively settled the Illinois taxing authority examination of the 2003 through 2006 tax years of PELLC and its consolidated subsidiaries. This effective settlement, combined with other certain state income tax examinations and a remeasurement of uncertain tax positions, decreased our liability for unrecognized tax benefits by $11.1 million. We reduced the provision for income taxes related to these items, of which a portion was reported as discontinued operations.

As of December 31, 2012, we were subject to examination by foreign income tax authorities for the 2007 through 2010 tax years. With a few exceptions, we are no longer subject to foreign income tax examinations by tax authorities for years prior to 2008.

In the first quarter of 2013, it is highly likely that we will decrease our liability for unrecognized tax benefits by $7.2 million. In the next 12 months, it is also reasonably possible that we and our subsidiaries will settle open examinations in multiple taxing jurisdictions related to tax years prior to 2011, resulting in a further decrease in unrecognized tax benefits of as much as $3.8 million.

NOTE 15—COMMITMENTS AND CONTINGENCIES

(a) Unconditional Purchase Obligations and Purchase Order Commitments

We and our subsidiaries routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. The regulated natural gas utilities have obligations to distribute and sell natural gas to their customers, and the regulated electric utilities have obligations to distribute and sell electricity to their customers. The utilities expect to recover costs related to these obligations in future customer rates. Additionally, the majority of the energy supply contracts entered into by Integrys Energy Services are to meet its obligations to deliver energy to customers. The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2012, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Date Contracts Extend	Total Amounts Committed	2013	2014	2015	2016	2017	Later Years

	Through							
Natural gas utility supply and transportation	2028	$704.0	$154.2	$109.1	$91.9	$84.5	$72.3	$192.0
Electric utility								
Purchased power	2029	959.5	226.9	37.8	33.1	29.6	28.7	603.4
Coal supply and transportation	2017	136.7	55.9	42.3	31.5	6.5	0.5	—
Nonregulated electricity and natural gas supply	2020	594.3	406.8	156.4	23.1	3.4	0.6	4.0
Total		$2,394.5	$843.8	$345.6	$179.6	$124.0	$102.1	$799.4

We and our subsidiaries also had commitments of $562.0 million in the form of purchase orders issued to various vendors at December 31, 2012, that relate to normal business operations, including construction projects.

(b) Environmental Matters

Air Permitting Violation Claims

Weston and Pulliam Clean Air Act (CAA) Issues:
In November 2009, the EPA issued a Notice of Violation (NOV) to WPS alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. WPS reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree, which was filed in the U.S. District Court (Court) on January 4, 2013. The Consent Decree includes:

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

The Court must review public comments filed by the Sierra Club and Clean Wisconsin before approving the Consent Decree. The final terms of the Consent Decree may be different than currently anticipated.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain Weston and Pulliam units. As of December 31, 2012, no decision had been made on how to address this requirement. Therefore, retirement of the Weston and Pulliam units mentioned in the Consent Decree was not considered probable.

Any costs prudently incurred as a result of actions taken due to the Consent Decree, with the exception of the civil penalty, are expected to be recoverable from customers.

In May 2010, WPS received from the Sierra Club a Notice of Intent (NOI) to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but further action by the Sierra Club is unknown at this time.

Columbia and Edgewater CAA Issues:
In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants (including WPS). The NOV alleges violations of the CAA's New Source Review requirements related to certain projects completed at those plants.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Edgewater plant did not comply with the CAA. The case was stayed until July 2012, and a request was made by WP&L to further extend the stay and all deadlines. An update was filed with the Court in August 2012, regarding the settlement negotiations with the Sierra Club, the EPA, and the joint owners of the Edgewater plant.

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

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

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

Weston Title V Air Permit:
In November 2010, the WDNR provided a draft revised permit for the Weston 4 plant. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR and met with the WDNR to resolve these issues. In September 2011, the WDNR issued an updated draft revised permit and a request for public comments. Due to the significance of the changes to the draft revised permit, the WDNR re-issued the draft revised permit for additional comments on February 4, 2013. In July 2012, Clean Wisconsin filed suit against the WDNR alleging failure to issue or delay in issuing the Weston 4 Title V permit. WPS is not a party to this litigation, but filed a request for intervention to

protect its interests. The motions for intervention and dismissal filed by WPS and the WDNR were granted on February 15, 2013. Clean Wisconsin has the right to appeal this decision. We do not expect this matter to have a material impact on our financial statements.

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

In April 2011, WPS received notification that the Sierra Club filed a civil lawsuit against the EPA based on what the Sierra Club alleged to be an unreasonable delay in responding to the June 2010 order. WPS is not a party to this litigation, but intervened to protect its interests. In February 2012, the WDNR sent a proposed permit and response to the EPA for a 45-day review, which allowed the parties to enter into a settlement agreement that has been approved by the Court.

In May 2012, the Sierra Club filed another Petition requesting the EPA to again object to the proposed permit and response, which the EPA denied on January 7, 2013. The Sierra Club also recently filed a request for a contested case proceeding regarding the permit, which was granted in part by the WDNR. A schedule has not yet been set for the contested case proceeding.

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 February 2011, the Sierra Club filed a lawsuit against the EPA seeking to have the EPA take over the Title V permit process for the Columbia plant. The Sierra Club alleges the EPA must now act on the reconsideration of the Title V permit since the WDNR has exceeded its timeframe in which to respond to an EPA order issued in 2009. In May 2011, the WDNR issued a revised draft Title V permit in response to the EPA's order.

In June 2012, WP&L received notice from the EPA of the EPA's proposal for WP&L to apply for a federally-issued Title V permit since the WDNR has not addressed the EPA's objections to the Title V permit issued for the Columbia plant. WP&L has until March 15, 2013, to comment on the EPA's proposal. If the EPA decides to require the submittal of an operation permit application, it would be due within six months of the EPA's notice to WP&L. WP&L believes the previously issued Title V permit for the Columbia plant is still valid. We do not expect this matter to have a material impact on our financial statements.

WDNR Issued NOVs:
Since 2008, WPS received four NOVs from the WDNR alleging various violations of the different air permits for the entire Weston plant; and Weston 1, Weston 2, and Weston 4 individually. WPS also received an NOV for a clerical error involving pages missing from a quarterly report for Weston. Corrective actions have been taken for the events in the five NOVs. In December 2011, the WDNR referred several of the claims in the NOVs to the state Justice Department for enforcement. WPS and the Justice Department began discussing the pending NOVs and their resolution in late 2012. We do not expect this matter to have a material impact on our financial statements.

Weston 4 Construction Permit

From 2004 to 2009, the Sierra Club filed various petitions objecting to the construction permit issued for the Weston 4 plant. In June 2010, the Wisconsin Court of Appeals affirmed the Weston 4 construction permit, but directed the WDNR to reopen the permit to set specific visible emissions limits. In July 2010, WPS, the WDNR, and the Sierra

Club filed Petitions for Review with the Wisconsin Supreme Court. In March 2011, the Wisconsin Supreme Court denied all Petitions for Review. Other than the specific visible emissions limits issue, all other challenges to the construction permit are now resolved. WPS is working with the WDNR to resolve this issue as part of the current construction permit renewal process. We do not expect this matter to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule requires a 40% reduction from historical baseline mercury emissions, beginning January 1, 2010, through the end of 2014. Beginning in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the historical baseline. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts, but less than 150 megawatts, must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of December 31, 2012, WPS estimates capital costs of approximately $2 million, which includes estimates for both wholly owned and jointly owned plants, to achieve the required reductions. The capital costs are expected to be recovered in future rates.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. The State of Wisconsin is assessing how its current mercury rule will be impacted by the MATS rule. We are currently evaluating options for achieving the emission limits specified in this rule, but we do not anticipate the cost of compliance to be significant. We expect to recover future compliance costs in future rates.

Sulfur Dioxide and Nitrogen Oxide:
In July 2011, the EPA issued a final rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including WPS, challenged in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The new rule was to become effective January 1, 2012. However, in December 2011, the CSAPR requirements were stayed by the D.C. Circuit and a previous rule, the Clean Air Interstate Rule (CAIR), was implemented during the stay period. In August 2012, the D.C. Circuit issued their ruling vacating and remanding CSAPR and simultaneously reinstating CAIR pending the issuance of a replacement rule by the EPA. In October 2012, the EPA and several other parties filed petitions for a rehearing of the D.C. Circuit's decision, which the D.C. Circuit denied on January 24, 2013.

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

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

Manufactured Gas Plant Remediation

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

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. As of December 31, 2012, we estimated and accrued for $650.0 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 December 31, 2012, cash expenditures for environmental remediation not yet recovered in rates were $38.7 million. We recorded a regulatory asset of $688.7 million at December 31, 2012, which is net of insurance recoveries received of $60.1 million, related to the expected recovery through rates of both cash expenditures and estimated future expenditures.

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

NOTE 16—GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at December 31, 2012	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1]	$631.5	$391.8	$29.0	$210.7
Standby letters of credit [2]	30.6	29.2	1.4	—
Surety bonds [3]	14.8	14.7	0.1	—
Other guarantees [4]	42.3	20.0	—	22.3
Total guarantees	$719.2	$455.7	$30.5	$233.0

(1) Consists of our guarantees of $468.8 million to support the business operations of Integrys Energy Services; $106.8 million and $48.9 million, respectively, related to natural gas supply at MERC and MGU; and $5.0 million at IBS, and $2.0 million at UPPCO to support business operations. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $28.9 million issued to support Integrys Energy Services' operations and $1.7 million related to letters of credit issued to support MERC, MGU, NSG, PGL, Pinnacle CNG Systems, UPPCO, and WPS. These amounts are not reflected on our balance sheets.

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

(4) Consists of (a) $20.0 million related to the sale agreement for Integrys Energy Services' United States wholesale electric marketing and trading business, which included a number of customary representations, warranties, and indemnification provisions. This amount is not reflected on our balance sheets; (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 our balance sheets; and (d) $7.3 million related to other indemnifications primarily for workers compensation coverage. These amounts are not reflected on our balance sheets.

We have provided total guarantees of $536.4 million on behalf of Integrys Energy Services. Our exposure under these guarantees related to open transactions at December 31, 2012, was $236.7 million.

NOTE 17—EMPLOYEE BENEFIT PLANS

Defined Benefit Plans

We and our subsidiaries maintain one noncontributory, qualified pension plan covering substantially all employees, as well as several unfunded nonqualified retirement plans. In addition, we and our subsidiaries offer multiple other postretirement benefit plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. As of February 16, 2012, our defined benefit pension plans are closed to all new hires.

We also currently offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets during 2012 and 2011:

	Pension Benefits		Other Benefits	
(Millions)	2012	2011	2012	2011
Change in benefit obligation				
Obligation at January 1	$1,563.1	$1,418.5	$576.8	$538.5
Service cost	46.0	41.4	20.8	19.0
Interest cost	78.0	80.1	28.5	29.5
Plan amendments	—	—	—	(0.8)
Actuarial loss, net	196.6	111.7	14.3	9.2
Participant contributions	—	—	10.6	10.6
Benefit payments	(98.8)	(88.6)	(32.1)	(31.8)
Federal subsidy on benefits paid	—	—	2.1	2.6
Obligation at December 31	$1,784.9	$1,563.1	$621.0	$576.8
Change in fair value of plan assets				
Fair value of plan assets at January 1	$1,099.5	$1,081.3	$285.5	$266.2
Actual return on plan assets	173.6	16.5	46.3	(1.0)
Employer contributions	173.8	90.3	114.1	41.2
Participant contributions	—	—	10.6	10.6
Benefit payments	(98.8)	(88.6)	(32.1)	(31.5)*

Fair value of plan assets at December 31	$1,348.1	$1,099.5	$424.4	$285.5
Funded Status at December 31	$(436.8)	$(463.6)	$(196.6)	$(291.3)

* Amount is net of early retirement reinsurance program payments received in 2011.

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Benefits		Other Benefits	
(Millions)	2012	2011	2012	2011
Current liabilities	$7.9	$5.3	$0.3	$0.3
Noncurrent liabilities	428.9	458.3	196.3	291.0
Total liabilities	$436.8	$463.6	$196.6	$291.3

The accumulated benefit obligation for all defined benefit pension plans was $1.6 billion and $1.4 billion at December 31, 2012, and 2011, respectively. Information for pension plans with an accumulated benefit obligation in excess of plan assets is presented in the following table:

	December 31	
(Millions)	2012	2011
Projected benefit obligation	$1,784.9	$1,563.1
Accumulated benefit obligation	1,594.7	1,388.0
Fair value of plan assets	1,348.1	1,099.5

The following table shows the amounts that had not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Benefits		Other Benefits	
(Millions)	2012	2011	2012	2011
Accumulated other comprehensive loss (pre-tax) [1]				
Net actuarial loss	$59.1	$51.5	$1.3	$1.0
Prior service costs (credits)	0.2	0.4	(0.6)	(1.0)
Total	$59.3	$51.9	$0.7	$—
Net regulatory assets [2]				
Net regulatory assets [2]				
Net actuarial loss	$683.1	$593.8	$117.3	$127.4
Prior service costs (credits)	6.2	11.0	(14.3)	(17.3)
Transition obligation	—	—	—	0.3
Total	$689.3	$604.8	$103.0	$110.4

[1] Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

[2] Amounts related to the regulated utilities are recorded as regulatory assets or liabilities.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2013:

(Millions)	Pension Benefits	Other Benefits
Net actuarial losses	$53.8	$8.2
Prior service costs (credits)	4.1	(2.5)
Total 2013 – estimated amortization	$57.9	$5.7

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

	Pension Benefits			Other Benefits		
(Millions)	2012	2011	2010	2012	2011	2010
Net periodic benefit cost						
Service cost	$46.0	$41.4	$40.1	$20.8	$19.0	$16.3
Interest cost	78.0	80.1	80.0	28.5	29.5	27.5
Expected return on plan assets	(107.9)	(100.0)	(92.3)	(28.2)	(21.4)	(19.0)
Amortization of transition obligation	—	—	—	0.3	0.3	0.3
Amortization of prior service cost (credit)	5.0	5.3	5.3	(3.4)	(3.9)	(3.8)
	34.0	18.1	8.1	6.6	4.0	1.9

Amortization of net actuarial loss							
Regulatory deferral *	—	—	4.5	—	—	(1.3	)
Net periodic benefit cost	$55.1	$44.9	$45.7	$24.6	$27.5	$21.9	

* The PSCW authorized recovery for net increased 2009 WPS pension and other postretirement benefit costs related to plan asset losses that occurred in 2008. Amortization and recovery of these deferred costs occurred in 2010.

Assumptions – Pension and Other Postretirement Benefit Plans

The weighted-average assumptions used to determine the benefit obligations at December 31 were as follows:

	Pension Benefits		Other Benefits	
	2012	2011	2012	2011
Discount rate	4.07%	5.10%	3.96%	4.94%
Rate of compensation increase	4.25%	4.26%	N/A	N/A
Assumed medical cost trend rate (under age 65)	N/A	N/A	7.00%	7.00%
Ultimate trend rate	N/A	N/A	5.00%	5.00%
Year ultimate trend rate is reached	N/A	N/A	2019	2016
Assumed medical cost trend rate (over age 65)	N/A	N/A	7.00%	7.50%
Ultimate trend rate	N/A	N/A	5.00%	5.50%
Year ultimate trend rate is reached	N/A	N/A	2019	2016
Assumed dental cost trend rate	N/A	N/A	5.00%	5.00%

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Benefits		
	2012	2011	2010
Discount rate	5.10%	5.80%	6.15%
Expected return on assets	8.25%	8.25%	8.50%
Rate of compensation increase	4.25%	4.26%	4.26%

	Other Benefits		
	2012	2011	2010
Discount rate	4.94%	5.66%	5.95%
Expected return on assets	8.25%	8.25%	8.50%
Assumed medical cost trend rate (under age 65)	7.00%	7.50%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%
Year ultimate trend rate is reached	2016	2016	2013
Assumed medical cost trend rate (over age 65)	7.50%	8.00%	8.50%
Ultimate trend rate	5.50%	5.50%	5.50%
Year ultimate trend rate is reached	2016	2016	2013
Assumed dental cost trend rate	5.00%	5.00%	5.00%

We establish our expected return on assets assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. Beginning in 2013, the expected return on assets assumption for the plans is 8.00%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for our health care plans. For the year ended December 31, 2012, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

	One-Percentage-Point	
(Millions)	Increase	Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$7.9	$(10.7)
Effect on the health care component of the accumulated postretirement benefit obligation	85.4	(109.0)

Pension and Other Postretirement Benefit Plan Assets

Our investment policy includes various guidelines and procedures designed to ensure assets are invested in an appropriate manner to meet expected future benefits to be earned by participants. The investment guidelines consider a broad range of economic conditions. Our policy is established and administered in a manner that is compliant at all times with applicable regulations.

Central to our policy are target allocation ranges by major asset categories. The objectives of the target allocations are to maintain investment portfolios that diversify risk through prudent asset allocation parameters and to achieve asset returns that meet or exceed the plans' actuarial assumptions and that are competitive with like instruments employing similar investment strategies. The portfolio diversification provides protection against significant concentrations of risk in the plan assets. The target asset allocations for pension and other postretirement benefit plans that have significant assets are: 70% equity securities and 30% fixed income securities. Equity securities primarily include investments in large-cap and small-cap companies. Fixed income securities primarily include corporate bonds of companies from diversified industries, United States government securities, and mortgage-backed securities.

The Board of Directors established the Employee Benefits Administrator Committee (composed of members of management) to manage the operations and administration of all benefit plans and trusts. The committee periodically reviews the asset allocation, and the portfolio is rebalanced when necessary.

Pension and other postretirement benefit plan investments are recorded at fair value. Information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used are discussed in Note 1(s), "Summary of Significant Accounting Policies – Fair Value."

The following table provides the fair values of our investments by asset class:

	December 31, 2012							
	Pension Plan Assets				Other Benefit Plan Assets			
(Millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$6.4	$25.3	$—	$31.7	$—	$9.5	$—	$9.5
Equity securities:								
United States equity	167.9	403.0	—	570.9	27.8	129.0	—	156.8
International equity	96.0	300.4	—	396.4	15.6	92.9	—	108.5
Fixed income securities:								
United States government	—	100.3	—	100.3	112.7	—	—	112.7
Foreign government	—	20.4	4.1	24.5	—	—	—	—
Corporate debt	—	197.3	1.0	198.3	—	—	—	—
Asset-backed securities	—	56.5	0.1	56.6	—	—	—	—
Other	—	11.3	—	11.3	1.1	—	—	1.1
	270.3	1,114.5	5.2	1,390.0	157.2	231.4	—	388.6
401(h) other benefit plan assets invested as pension assets (1)	(7.1)	(29.3)	(0.1)	(36.5)	7.1	29.3	0.1	36.5
Total (2)	$263.2	$1,085.2	$5.1	$1,353.5	$164.3	$260.7	$0.1	$425.1

(1) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(2) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

	December 31, 2011							
	Pension Plan Assets				Other Benefit Plan Assets			
(Millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$4.4	$23.7	$—	$28.1	$—	$5.8	$—	$5.8
Equity securities:								
United States equity	126.9	321.7	—	448.6	24.8	79.5	—	104.3
International equity	69.1	247.0	—	316.1	13.1	57.9	—	71.0

Fixed income securities:								
United States government	—	93.2	—	93.2	75.2	—	—	75.2
Foreign government	—	17.1	5.7	22.8	—	—	—	—
Corporate debt	—	156.5	2.1	158.6	—	—	—	—
Asset-backed securities	—	55.1	—	55.1	—	—	—	—
Other	—	8.1	—	8.1	1.8	—	—	1.8
	200.4	922.4	7.8	1,130.6	114.9	143.2	—	258.1
401(h) other benefit plan assets invested as pension assets [1]	(4.9)	(22.6)	(0.2)	(27.7)	4.9	22.6	0.2	27.7
Total [2]	$195.5	$899.8	$7.6	$1,102.9	$119.8	$165.8	$0.2	$285.8

(1) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(2) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

85

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy:

(Millions)	Foreign Government Debt	Corporate Debt	Asset-Backed Securities	Total
Beginning balance at December 31, 2011	$5.7	$2.1	$—	$7.8
Net realized and unrealized gains	0.5	0.2	—	0.7
Purchases	1.2	0.5	—	1.7
Sales	(2.0)	(0.4)	—	(2.4)
Transfers into Level 3	—	—	0.1	0.1
Transfers out of Level 3	(1.3)	(1.4)	—	(2.7)
Ending balance at December 31, 2012	$4.1	$1.0	$0.1	$5.2
Net unrealized gains related to assets still held at the end of the period	$0.3	$0.1	$—	$0.4

(Millions)	Foreign Government Debt	Corporate Debt	Asset-Backed Securities	Real Estate Securities	Total
Beginning balance at December 31, 2010	$7.8	$2.0	$0.2	$30.0	$40.0
Net realized and unrealized gains (losses)	—	(0.1)	—	0.9	0.8
Purchases	2.2	2.1	—	1.9	6.2
Sales	(4.3)	(1.9)	—	(32.8)	(39.0)
Settlements	—	—	(0.1)	—	(0.1)
Transfers into Level 3	—	0.2	—	—	0.2
Transfers out of Level 3	—	(0.2)	(0.1)	—	(0.3)
Ending balance at December 31, 2011	$5.7	$2.1	$—	$—	$7.8
Net unrealized losses related to assets still held at the end of the period	$(0.2)	$(0.1)	$—	$—	$(0.3)

Cash Flows Related to Pension and Other Postretirement Benefit Plans

Our funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. We expect to contribute $67.9 million to pension plans and $32.9 million to other postretirement benefit plans in 2013, dependent on various factors affecting us, including our liquidity position and tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and other postretirement benefits. In addition, the table shows the expected federal subsidies, provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003, which will partially offset other postretirement benefits.

(Millions)	Pension Benefits	Other Benefits	Federal Subsidies
2013	$132.3	$28.8	$2.2
2014	123.8	30.9	2.4
2015	122.0	33.4	2.5
2016	124.4	36.0	2.6

2017	128.9	38.6	2.7
2018 through 2022	665.8	229.8	15.9

Defined Contribution Benefit Plans

We maintain 401(k) Savings Plans for substantially all of our full-time employees. We match a percentage of employee contributions through an employee stock ownership plan (ESOP) or cash contribution up to certain limits. Certain union employees receive a contribution to their ESOP account regardless of their participation in the 401(k) Savings Plan. The ESOP held 3.6 million shares of our common stock (market value of $189.0 million) at December 31, 2012. Certain employees who are not eligible to participate in the defined benefit pension plan participate in a defined contribution pension plan, in which we contribute certain amounts to an employee's account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $19.1 million in 2012, $17.0 million in 2011, and $16.9 million in 2010.

We maintain deferred compensation plans that enable certain key employees and nonemployee directors to defer payment of a portion of their compensation or fees on a pre-tax basis. Nonemployee directors can defer up to 100% of their director fees. Compensation is generally deferred in the form of cash and is indexed to certain investment options or our common stock. The deemed dividends paid on our common stock are automatically reinvested.

The deferred compensation arrangements for which distributions are made solely in our common stock are classified as an equity instrument. Changes in the fair value of this portion of the deferred compensation obligation are not recognized. The deferred compensation obligation classified as an equity instrument was $23.9 million at December 31, 2012, and $24.1 million at December 31, 2011.

The portion of the deferred compensation obligation that allows for distributions in cash is classified as a liability on the balance sheets. The liability is adjusted, with a charge or credit to expense, to reflect changes in the fair value of the deferred compensation obligation. The obligation classified within other long-term liabilities was $42.9 million at December 31, 2012, and $39.1 million at December 31, 2011. The costs incurred under this arrangement were $3.1 million in 2012, $2.1 million in 2011, and $3.5 million in 2010.

The deferred compensation programs are partially funded through shares of our common stock that are held in a rabbi trust. The common stock held in the rabbi trust is classified as a reduction of equity in a manner similar to accounting for treasury stock. The total cost of our common stock held in the rabbi trust was $17.7 million at December 31, 2012, and $17.1 million at December 31, 2011.

NOTE 18—PREFERRED STOCK OF SUBSIDIARY

Our subsidiary, WPS, has 1,000,000 authorized shares of preferred stock with no mandatory redemption and a $100 par value. Outstanding shares owned by third parties were as follows at December 31:

(Millions, except share amounts)	2012		2011	
Series	Shares Outstanding	Carrying Value	Shares Outstanding	Carrying Value
5.00%	130,692	$13.1	130,692	$13.1
5.04%	29,898	3.0	29,898	3.0
5.08%	49,905	5.0	49,905	5.0
6.76%	150,000	15.0	150,000	15.0
6.88%	150,000	15.0	150,000	15.0
Total	510,495	$51.1	510,495	$51.1

All shares of WPS preferred stock of all series are of equal rank except as to dividend rates and redemption terms. Payment of dividends from any earned surplus or other available surplus is not restricted by the terms of any indenture or other undertaking by WPS. Each series of outstanding preferred stock is redeemable in whole or in part at WPS's option at any time on 30 days' notice at the respective redemption prices. WPS may not redeem less than all, nor purchase any, of our preferred stock during the existence of any dividend default.

In the event of WPS's dissolution or liquidation, the holders of preferred stock are entitled to receive (a) the par value of their preferred stock out of the corporate assets other than profits before any of such assets are paid or distributed to the holders of common stock and (b) the amount of dividends accumulated and unpaid on their preferred stock out of the surplus or net profits before any of such surplus or net profits are paid to the holders of common stock. Thereafter, the remainder of the corporate assets, surplus, and net profits would be paid to the holders of common stock.

The preferred stock has no pre-emptive, subscription, or conversion rights, and has no sinking fund provisions.

NOTE 19—COMMON EQUITY

We had no changes to issued common stock during 2012 and the following changes during 2011 and 2010:

	Common stock shares
Balance at December 31, 2009	76,418,843
Shares issued	
Stock Investment Plan	752,360
Stock-based compensation	592,237
Rabbi trust shares	35,000
Restricted stock shares cancelled	(16,755)
Balance 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 cancelled	(2,213)
Balance at December 31, 2011	78,287,906

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

Period	Method of meeting requirements
Beginning 02/05/2013	Issuing new shares
05/01/2011 – 02/04/2013	Purchased shares on the open market
02/11/2010 – 04/30/2011	Issued new shares *
01/01/2010 – 02/10/2010	Purchased shares on the open market

* These stock issuances increased equity $22.2 million in 2011.

The following table reconciles common shares issued and outstanding:

	2012 Shares	Average Cost		2011 Shares	Average Cost	
Common stock issued	78,287,906			78,287,906		
Less:						
Deferred compensation rabbi trust	385,439	$46.03	*	382,971	$44.54	*
Total common shares outstanding	77,902,467			77,904,935		

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

Earnings Per Share

Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for shares we are obligated to issue under the deferred compensation and restricted share unit plans. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, restricted share units, and certain shares issuable under the deferred compensation plan. The calculation of diluted earnings per share for both 2012 and 2011 excluded 0.7 million out-of-the-money stock options that had an anti-dilutive effect. The 2010 calculation of diluted earnings per share excluded 1.4 million out-of-the-money stock options that had an anti-dilutive effect. The following table reconciles our computation of basic and diluted earnings per share:

(Millions, except per share amounts)	2012	2011	2010
Numerator:			
Net income from continuing operations	$294.0	$230.0	$245.2
Discontinued operations, net of tax	(9.7)	0.5	(21.5)
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.2	—	0.3
Net income attributed to common shareholders	$281.4	$227.4	$220.9
Denominator:			
Average shares of common stock – basic	78.6	78.6	77.5
Effect of dilutive securities			
Stock-based compensation	0.5	0.5	0.5
Deferred compensation	0.2	—	—
Average shares of common stock – diluted	79.3	79.1	78.0
Earnings per common share			
Basic	$3.58	$2.89	$2.85

Diluted	3.55	2.87	2.83

Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss, net of tax, at December 31, 2012, and 2011, were:

(Millions)	2012	2011
Cash flow hedges [1]	$(5.2)	$(11.5)
Unrecognized pension and other postretirement benefit costs [2]	(35.7)	(31.0)
Total accumulated other comprehensive loss	$(40.9)	$(42.5)

[1] Net of tax benefits of $7.2 million and $9.1 million at December 31, 2012, and 2011, respectively.

[2] Net of tax benefits of $24.3 million and $20.9 million at December 31, 2012, and 2011, respectively.

Dividend Restrictions

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

The PSCW allows WPS to pay dividends on its common stock of no more than 103% of the previous year's common stock dividend. WPS may return capital to us if its average financial common equity ratio is at least 51.01% on a calendar-year basis. WPS must obtain PSCW approval if a return of capital would cause its average financial common equity ratio to fall below this level. Our right to receive dividends on the common stock of WPS is also subject to the prior rights of WPS's preferred shareholders and to provisions in WPS's restated articles of incorporation, which limit the amount of common stock dividends that WPS may pay if its common stock and common stock surplus accounts constitute less than 25% of its total capitalization.

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

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

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 December 31, 2012, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

As of December 31, 2012, total restricted net assets were $1,574.3 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $125.2 million at December 31, 2012.

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

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

Capital Transactions with Subsidiaries

During 2012, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
WPS	$105.5	$50.0	$40.0
WPS Investments, LLC (1)	68.4	—	20.4
PGL (2)	55.0	—	—
NSG (2)	10.0	—	—
MERC	—	18.0	11.0
IBS	—	23.0	10.0
MGU	—	8.0	—
UPPCO	—	11.5	8.5
Total	$238.9	$110.5	$89.9

(1) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At December 31, 2012, we had an 85.81% ownership interest, while WPS and UPPCO had an 11.70% and 2.49% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2012, all equity contributions to WPS Investments, LLC were made solely by us.

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

NOTE 20—STOCK-BASED COMPENSATION

In May 2010, our shareholders approved the 2010 Omnibus Incentive Compensation Plan (2010 Omnibus Plan). Under the provisions of the 2010 Omnibus Plan, the number of shares of stock that may be issued in satisfaction of plan awards may not exceed 3,000,000 shares, plus any shares remaining or forfeited under prior plans. No more than 900,000 shares of stock, plus shares remaining or forfeited under prior plans, can be granted as full value shares in the form of performance shares or restricted stock. No additional awards will be issued under prior plans, although the plans continue to exist for purposes of the existing outstanding stock-based compensation awards. At December 31, 2012, stock options, performance stock rights, and restricted share units were outstanding under the various plans.

The following table reflects the stock-based compensation expense and the related deferred tax benefit recognized in income for the years ended December 31:

(Millions)	2012	2011	2010
Stock options	$2.0	$1.8	$2.3
Performance stock rights	5.0	3.5	10.0
Restricted shares and restricted share units	9.7	6.1	10.1
Nonemployee director deferred stock units	1.0	1.0	0.9
Total stock-based compensation expense	$17.7	$12.4	$23.3
Deferred income tax benefit	$7.1	$5.0	$9.3

No stock-based compensation cost was capitalized during 2012, 2011, and 2010.

Stock Options

Our stock options have a term not longer than ten years. The exercise price of each stock option is equal to the fair market value of the stock on the date the stock option is granted. Generally, one-fourth of the stock options granted vest and become exercisable each year on the anniversary of the grant date. Under the provisions of the 2010 Omnibus Plan, no single employee who is our chief executive officer or one of our other three highest compensated officers (including officers of our subsidiaries) can be granted stock options for more than 1,000,000 shares during any calendar year.

The fair values of stock option awards granted are estimated using a binomial lattice model. The expected term of stock option awards is calculated based on historical exercise behavior and represents the period of time that stock 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 was estimated using 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:

	2012 Grant	2011 Grant	2010 Grant
Weighted-average fair value per stock option	$6.30	$6.57	$5.30
Expected term	5 years	5 years	6 years
Risk-free interest rate	0.17% – 2.18%	0.27% – 3.90%	2.38%
Expected dividend yield	5.28%	5.34%	5.46%
Expected volatility	25%	25%	25%

A summary of stock option activity for 2012, and information related to outstanding and exercisable stock options at December 31, 2012, is presented below:

	Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2011	2,953,630	$ 48.09		
Granted	279,535	53.24		
Exercised	(1,179,542)	47.29		
Forfeited	(5,943)	53.24		
Expired	(1,325)	40.01		
Outstanding at December 31, 2012	2,046,355	$ 49.25	5.82	$8.3
Exercisable at December 31, 2012	1,246,825	$ 50.42	4.50	$4.2

As of December 31, 2012, $1.0 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.3 years.

Cash received from option exercises during 2012, 2011, and 2010 was $55.8 million, $2.3 million, and $18.8 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $4.4 million during 2012, and was not significant in 2011, and 2010.

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they all exercised their options at December 31, 2012. This is calculated as the difference between our closing stock price on December 31, 2012, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during 2012, 2011, and 2010 was $11.0 million, $2.8 million, and $4.9 million, respectively.

Performance Stock Rights

Performance stock rights vest over a three-year performance period. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the distribution of these awards is not accelerated. No single employee who is our chief executive officer or one of our other three highest compensated officers (including officers of our subsidiaries) can receive a payout in excess of 250,000 performance shares during any calendar year. Performance stock rights are paid out in shares of our common stock, or eligible employees can elect to defer the value of their awards into the deferred compensation plan and choose among various investment options, some of which are ultimately paid out in our common stock and some of which are ultimately paid out in cash.

Beginning in 2011, eligible employees can only elect to defer up to 80% of the value of their awards. The number of shares paid out is calculated by multiplying a performance percentage by the number of outstanding stock rights at the completion of the performance period. The performance percentage is based on the total shareholder return of our common stock relative to the total shareholder return of a peer group of companies. The payout may range from 0% to 200% of target.

Performance stock rights are accounted for as either an equity award or a liability award depending on their settlement features. Awards that can only be settled in our common stock are accounted for as equity awards. Awards that an employee has elected to defer or is still able to defer into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

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

The fair values of performance stock rights were estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. The expected volatility was estimated using one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at December 31:

	2012	2011	2010
Risk-free interest rate	0.17% – 1.27 %	0.00% – 1.27%	0.21% – 0.56%
Expected dividend yield	5.18 % – 5.34 %	5.28% – 5.34%	5.34%
Expected volatility	14% – 36%	21% – 36%	20% – 34%

A summary of the 2012 activity related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value*
Outstanding at December 31, 2011	135,948	$ 46.18
Granted	18,865	52.70
Award modifications	49,304	79.62
Distributed	(70,598)	42.93
Adjustment for final payout	(24,804)	42.93
Forfeited	(401)	52.70
Outstanding at December 31, 2012	108,314	$ 65.38

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

A summary of the 2012 activity related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2011	186,215
Granted	75,408
Award modifications	(49,304)
Distributed	(16,001)
Adjustment for final payout	(5,622)
Forfeited	(1,603)
Outstanding at December 31, 2012	189,093

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of December 31, 2012, was $48.47 per performance stock right.

As of December 31, 2012, $1.5 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.6 years.

The total intrinsic value of performance shares distributed during the years ended December 31, 2012 and 2011, was $4.7 million and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance shares during the years ended December 31, 2012, and 2011, was $1.9 million and $2.5 million, respectively.

Restricted Shares and Restricted Share Units

Restricted shares and restricted share units generally have a four-year vesting period, with 25% of each award vesting on each anniversary of the grant date. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the releasing of these shares to these employees is not accelerated. During 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at December 31, 2012. Restricted share unit recipients do not have voting rights, but they receive forfeitable dividend equivalents in the form of additional restricted share units.

Restricted share units are accounted for as either an equity award or a liability award depending on their settlement features. Awards that can only be settled in our common stock and cannot be deferred into the deferred compensation plan are accounted for as equity awards. Beginning in 2011, eligible employees can only elect to defer up to 80% of their awards into the deferred compensation plan. Equity awards are measured based on the fair value on the grant date. Awards that an employee has elected to defer into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the year ended December 31, 2012, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2011	497,722	$ 45.21
Granted	188,346	53.24
Dividend equivalents	24,968	48.38
Vested and released	(199,599)	45.14
Forfeited	(5,747)	50.00
Outstanding at December 31, 2012	505,690	$ 48.38

As of December 31, 2012, $10.1 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.3 years.

The total intrinsic value of restricted share and restricted share unit awards vested and released for the years ended December 31, 2012, 2011, and 2010, was $10.7 million, $7.5 million, and $4.9 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and releasing of restricted shares and restricted share units during the years ended December 31, 2012, 2011, and 2010, was $4.3 million, $3.0 million, and $2.0 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during the years ended December 31, 2012, 2011, and 2010, was $53.24, $49.39, and $41.67 per share, respectively.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. The number of DSUs granted is calculated by dividing a set dollar amount by our closing common stock price on the date of the grant. Under the terms of the agreement, these awards vest immediately. Therefore, they are expensed on the grant date.

NOTE 21—VARIABLE INTEREST ENTITIES

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture will be loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At December 31, 2012, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of AMP Trillium LLC assets and liabilities included on our December 31, 2012, balance sheet were also not significant.

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. ITF and Paper Transport Inc. each own 50% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture will be loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At December 31, 2012, and December 31, 2011, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of Integrys PTI CNG Fuels LLC assets and liabilities included on our balance sheets were also not significant.

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these agreements reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under the agreement. This contract for 17.5 megawatts of capacity expires in 2014. The other agreement contains a 500 megawatt tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. In connection with the pending purchase of Fox Energy Company LLC, WPS will pay $50.0 million to terminate this tolling arrangement. See Note 3, "Acquisitions," for more information regarding this pending purchase. As of December 31, 2012, and December 31, 2011, we had a total of 517.5 megawatts of capacity available under these agreements. We evaluated both of these variable interest entities for possible consolidation. We considered which interest holder has the power to direct the activities that most significantly impact the economics of the variable interest entity; this interest holder is considered the primary beneficiary of the entity and is required to consolidate the entity. For a variety of reasons, including qualitative factors such as the length of the remaining term of the contracts compared with the remaining lives of the plants and the fact that we do not have the power to direct the operations and maintenance of the facilities, we determined we are not the primary beneficiary of these variable interest entities. At December 31, 2012, and December 31, 2011, the assets and liabilities on the balance sheets that related to our involvement with these variable interest entities pertained to working capital accounts and represented the amounts we owed for current deliveries of power. We have not guaranteed any debt or provided any equity support, liquidity arrangements, performance guarantees, or other commitments associated with these contracts. There is not a significant potential exposure to loss as a result of involvement with the variable interest entities.

NOTE 22—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:

	December 31, 2012			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$0.3	$3.1	$—	$3.4
Financial transmission rights (FTRs)	—	—	2.1	2.1
Petroleum product contracts	0.2	—	—	0.2
Coal contracts	—	—	2.5	2.5
Nonregulated Segments				
Natural gas contracts	21.4	36.4	5.4	63.2
Electric contracts	48.4	61.3	9.6	119.3
Total Risk Management Assets	$70.3	$100.8	$19.6	$190.7
Investment in exchange-traded funds	$11.8	$—	$—	$11.8
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$1.1	$14.1	$—	$15.2
FTRs	—	—	0.1	0.1
Coal contracts	—	—	9.0	9.0
Nonregulated Segments				
Natural gas contracts	17.7	36.9	1.5	56.1
Electric contracts	54.9	91.1	13.9	159.9
Total Risk Management Liabilities	$73.7	$142.1	$24.5	$240.3

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

* Includes a $0.1 million risk management liability that was classified as held for sale at Integrys Energy Services. See Note 4, "Dispositions," for more information.

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 2, "Risk Management Activities."

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

	Nonregulated Segments – Natural Gas Contracts					
	December 31, 2012			December 31, 2011		
(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	2.0	$—	N/A	24.4
Transfers into Level 3 from	—	3.7	N/A	—	0.6	N/A

	Nonregulated Segments – Electric Contracts					
	December 31, 2012			December 31, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	$—	N/A	$—	$(1.8)

Transfers into Level 2 from	$—	N/A	(13.0)	$3.4	N/A	(18.4)
Transfers into Level 3 from	—	(7.9)	N/A	0.7	(6.6)	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 significant unobservable inputs used in the valuation that resulted in categorization within Level 3 were as follows at December 31, 2012. The amounts and percentages listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a derivative transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	$2.1	$ 0.1	Market-based	Forward market prices ($/megawatt-month) (1)	178.86
Coal contracts	2.5	9.0	Market-based	Forward market prices ($/ton) (2)	13.30 - 15.70
Nonregulated Segments					
Natural gas contracts	5.4	1.5	Market-based	Forward market prices ($/dekatherm) (3)	(0.08) – 2.22
				Probability of default	11.6% – 51.0%
Electric contracts	9.6	13.9	Market-based	Forward market prices ($/megawatt-hours) (3)	(4.65) – 7.26
				Option volatilities (4)	19.8% – 110.1%

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

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

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

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

Significant changes in historical settlement prices, forward commodity prices, and option volatilities would result in a directionally similar significant change in fair value. Significant changes in probability of default would result in a significant directionally opposite change in fair value. Changes in the adjustments to prices related to monthly curve shaping would affect fair value differently depending on their direction.

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

2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$8.3	$(11.5)	$2.2	$(6.9)	$(7.9)
Net realized and unrealized gains (losses) included in earnings	3.8	(14.5)*	1.8	—	(8.9)*
Net unrealized gains recorded as regulatory assets or liabilities	—	—	0.2	5.8	6.0
Purchases	—	7.8	4.9	—	12.7
Sales	—	—	(0.1)	—	(0.1)
Settlements	(9.9)	8.8	(7.0)	(5.4)	(13.5)
Net transfers into Level 3	3.7	(7.9)	—	—	(4.2)

Net transfers out of Level 3	(2.0)	13.0	—	—	11.0
Balance at the end of the period	$3.9	$(4.3)	$2.0	$(6.5)	$(4.9)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$3.8	$(14.5)*	$—	$—	$(10.7)*

* Includes a $1.2 million net unrealized loss reported as discontinued operations. See Note 4, "Dispositions," for more information.

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	32.3	(20.7)*	(1.7)	—	9.9*
Net unrealized losses recorded as regulatory assets or liabilities	—	—	(1.7)	(8.0)	(9.7)
Net unrealized gains included in other comprehensive loss	—	0.6	—	—	0.6
Purchases	—	2.2	5.9	—	8.1
Sales	—	—	(0.1)	—	(0.1)
Settlements	(30.4)	7.0	(3.1)	(1.4)	(27.9)
Net transfers into Level 3	0.6	(5.9)	—	—	(5.3)
Net transfers out of Level 3	(24.4)	20.2	—	—	(4.2)
Balance at the end of the period	$8.3	$(11.5)	$2.2	$(6.9)	$(7.9)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$32.3	$(20.7)*	$—	$—	$11.6*

* Includes a $0.5 million net unrealized gain reported as discontinued operations. See Note 4, "Dispositions," for more information.

2010	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	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	38.9	(65.1)*	5.3	—	(20.9)*
Net unrealized (losses) gains recorded as regulatory assets or liabilities	—	—	(1.1)	2.5	1.4
Net unrealized losses included in other comprehensive loss	—	(3.1)	—	—	(3.1)
Net purchases and settlements	(41.0)	(43.7)	(4.8)	—	(89.5)
Net transfers into Level 3	1.7	(4.9)	—	—	(3.2)
Net transfers out of Level 3	(0.8)	15.4	—	—	14.6
Balance at the end of the period	$30.2	$(14.9)	$2.9	$2.5	$20.7
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$38.9	$(65.1)*	$—	$—	$(26.2)*

* Includes a $2.1 million net unrealized gain reported as discontinued operations. See Note 4, "Dispositions," for more information.

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 sales, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through utility cost of fuel, natural gas, and purchased power on the statements of income.

Fair Value of Financial Instruments

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

	2012		2011	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$2,245.2	$2,425.8	$2,122.0	*$2,281.5
Preferred stock of subsidiary	51.1	52.7	51.1	51.8

* Includes a $27.0 million loan classified as held for sale on our balance sheet related to the sale of WPS Westwood Generation, LLC. See Note 4, "Dispositions," and Note 12, "Long-term Debt," for more information.

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

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

NOTE 23—ADVERTISING COSTS

Costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. Capitalized direct-response advertising costs, net of accumulated amortization, totaled \$5.5 million and \$3.4 million as of December 31, 2012 and 2011, respectively. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment, and there was no impairment during the years ended December 31, 2012 and 2011.

Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years. The amortization of direct-response advertising costs was \$3.8 million and \$1.5 million for the years ended December 31, 2012 and 2011, respectively. There was no amortization of direct-response advertising costs for the year ended December 31, 2010.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. Other advertising expense was \$7.1 million, \$7.4 million, and \$7.8 million for the years ended December 31, 2012, 2011, and 2010, respectively.

NOTE 24—MISCELLANEOUS INCOME

Total miscellaneous income was as follows at December 31:

(Millions)	2012	2011	2010	
Equity portion of AFUDC	$2.9	$0.7	$1.6	
Key executive life insurance income	2.6	2.3	3.1	
Interest and dividend income	0.7	1.0	3.7	
Gain (loss) on foreign currency translation	(0.4)	—	4.7	*
Other	3.5	1.3	0.2	
Total miscellaneous income	$9.3	$5.3	$13.3	

* The foreign currency translation gains that had accumulated in OCI were reclassified from OCI and reported in other income in 2010 when Integrys Energy Services substantially completed the liquidation of its Canadian subsidiaries.

NOTE 25—REGULATORY ENVIRONMENT

Wisconsin

2013 Rates

On December 6, 2012, the PSCW issued an order approving a settlement agreement for WPS, effective January 1, 2013. The settlement agreement includes a $28.5 million imputed retail electric rate increase, which will be partially offset by the actual 2012 fuel refund of $20.5 million. The difference between the 2012 fuel refund and the rate increase will be deferred for recovery in a future rate proceeding. As a result, there will be no change to customers' 2013 retail electric rates. The settlement agreement also includes a $3.4 million retail natural gas rate decrease. The 2013 electric and natural gas rates are subject to downward adjustment based on updated December 31, 2012, pension and benefit cost estimates, which will be filed with the PSCW by March 1, 2013. The settlement agreement reflects a 10.30% return on common equity and a common equity ratio of 51.61% in WPS's regulatory capital structure. In addition, WPS was authorized recovery of $5.9 million related to income tax amounts previously expensed due to the Federal Health Care Reform Act. As a result, this amount was recorded as a regulatory asset at December 31, 2012. The settlement agreement also authorized the recovery of direct Cross State Air Pollution Rule (CSAPR) costs incurred through the end of 2012. As of December 31, 2012, WPS had deferred $4.7 million of costs related to CSAPR. Lastly, the settlement agreement also authorized WPS to switch from production tax credits to Section 1603 Grants for the Crane Creek Wind Project.

Decoupling for natural gas and electric residential and small commercial and industrial customers was approved as part of the settlement agreement on a pilot basis for 2013. The mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels, nor does it cover all customer classes. It is based on total rate case-approved margins, rather than being calculated on a per-customer basis. It will continue to include an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are subject to these caps and are included in rates upon approval in a rate order.

2012 Rates

On December 9, 2011, the PSCW issued a final written order for WPS, effective January 1, 2012. It authorized an electric rate increase of $8.1 million and required a natural gas rate decrease of $7.2 million. The electric rate increase was driven by projected increases in fuel and purchased power costs. However, to the extent that actual fuel and purchased power costs exceeded a 2% price variance from costs included in rates, they were deferred for recovery or refund in a future rate proceeding. The rate order allowed for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection, and reflected reduced contributions to the Focus on Energy Program. The rate order also allowed for the deferral of direct CSAPR compliance costs, including carrying costs.

2011 Rates

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

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

Michigan

MGU Depreciation Case

In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance of $2.5 million associated with the early retirement of certain MGU assets in 2010. As a result, MGU plans to modify its depreciation study currently pending before the MPSC to reflect recovery of these previously disallowed costs. The deadline to appeal the Michigan Court of Appeals' order is March 7, 2013.

2012 UPPCO Rates

On December 20, 2011, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $4.2 million, effective January 1, 2012. The new rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in UPPCO's regulatory capital structure. The order states that if UPPCO files a rate case in 2013, the earliest effective date for new final rates or self-implemented rates is January 1, 2014. Additionally, the order required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2013. The new decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. It includes an annual 1.5% cap based on distribution revenues approved in the rate case. UPPCO had no decoupling mechanism in place during 2012.

In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. This decision was not appealed. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. However, on August 14, 2012, the MPSC issued an order stating it had the authority to approve UPPCO's decoupling mechanism, as UPPCO's decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement. Therefore, in the third quarter of 2012, UPPCO reversed the $1.5 million previously expensed in the first quarter of 2012.

2011 UPPCO Rates

On December 21, 2010, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $8.9 million, effective January 1, 2011. The new rates reflected a 10.30% return on common equity and a common equity ratio of 54.86% in UPPCO's regulatory capital structure. The order required UPPCO to terminate its uncollectibles expense tracking mechanism after the close of December 2010 business, but retained the decoupling mechanism. The uncollectibles expense tracking mechanism allowed 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.

Illinois

2013 Rate Cases

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

In rebuttal testimony, the ICC Staff recommended rate increases of $14.9 million and $4.3 million for PGL and NSG, respectively, as well as a 9.06% return on common equity for both companies. Their recommendation also included a common equity ratio of 50.43% and 50.32% in PGL's and NSG's regulatory capital structures, respectively. Also in rebuttal testimony, the Illinois Attorney General recommended rate increases of $15.4 million and $2.6 million for PGL and NSG, respectively and assumed the existing approved return on equity for PGL and NSG. In surrebuttal testimony, PGL and NSG revised their requested natural gas rate increases to $97.8 million and $9.6 million, respectively, including a reduced requested return on common equity of 10.00%. The revised requests at PGL and NSG are primarily driven by increased costs due to new permitting and restoration requirements, as well as modifications in natural gas main and service pipe installation procedures.

2012 Rates

On January 10, 2012, the ICC issued a final order authorizing a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG, effective January 21, 2012. The rates for PGL reflected a 9.45% return on common equity and a common equity ratio of 49.00% in PGL's regulatory capital structure. The rates for NSG reflected a 9.45% return on common equity and a common equity ratio of 50.00% in NSG's regulatory capital structure. The rate order also approved a permanent decoupling mechanism.

The Illinois Attorney General appealed the ICC's approval of decoupling and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General's motion to make revenues collected under the permanent decoupling mechanism subject to refund. Refunds would be required if the Illinois

Appellate Court (Court) finds that the ICC did not have the authority to approve decoupling and the Court orders a refund. As a result, the recovery of amounts related to decoupling is uncertain. Therefore, PGL and NSG reduced revenues by $13.2 million in the second quarter of 2012 related to decoupling amounts accrued for regulatory recovery as of March 31, 2012. These amounts and decoupling amounts accrued thereafter have a reserve established against them equal to the amount accrued. As of December 31, 2012, a reserve of $16.5 million was recorded. In November 2012, PGL and NSG filed briefs with the Court defending the authority of the ICC to approve the decoupling mechanism. Since the decoupling mechanism is still in place, PGL and NSG also intend to file with the ICC for rate recovery, beginning in April 2013, for amounts accrued related to decoupling.

Infrastructure Cost Recovery Rider (Rider ICR)

On January 21, 2010, the ICC approved Rider ICR, a mechanism for PGL to earn a return on and recover the costs, above an annual baseline, of the AMRP through a special charge on customers' bills. However, the Illinois Appellate Court, First District, reversed the ICC's approval of Rider ICR, concluding it was improper single issue ratemaking. The ICC subsequently issued a remand order requiring that PGL refund $2.3 million, over a nine-month period beginning in July 2012, in the form of a refund and reconciliation adjustment. A refund amount of $1.1 million was included in PGL's regulatory liabilities as of December 31, 2012.

Minnesota

2011 Rates

On July 13, 2012, the MPUC approved a written order for MERC authorizing a retail natural gas rate increase of $11.0 million, effective January 1, 2013. The new rates reflect a 9.70% return on common equity and a common equity ratio of 50.48% in MERC's regulatory capital structure. In addition, the order set recovery of MERC's 2011 test-year pension expense at 2010 levels. The MPUC also approved a decoupling mechanism for MERC that covers residential and small commercial and industrial customers on a three-year trial basis, effective January 1, 2013. The decoupling mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels. It includes an annual 10% cap based on distribution revenues approved in the rate case. Amounts recoverable from or refundable to customers are subject to this cap.

Federal

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

Integrys Energy Services initially expensed the majority of the total $19.2 million of billings received during the transitional period. The remaining amount was considered probable of recovery due to inconsistencies between the FERC's SECA order and the transmission owners' FERC-ordered compliance filings. Integrys Energy Services protested the FERC’s SECA order, and in August 2006, the Administrative Law Judge hearing the case issued an Initial Decision that was in substantial agreement with all of Integrys Energy Services' positions. In May 2010, the FERC ruled favorably for Integrys Energy Services on two issues, but reversed the rulings of the Initial Decision on nearly every other substantive issue. Integrys Energy Services and numerous other parties filed for rehearing of the FERC's order on the Initial Decision, which the FERC denied on September 30, 2011. The FERC has yet to issue an order on the compliance filings made by the transmission owners. Integrys Energy Services has appealed the adverse FERC decision to the U.S. Court of Appeals for the D.C. Circuit. As a result of the rulings received from the FERC in

May 2010, Integrys Energy Services had a $3.8 million receivable recorded at December 31, 2012.

In January 2013, Integrys Energy Services reached a settlement with American Electric Power Service Corporation (AEP), and filed a Joint Stipulation and Agreement ("Settlement Agreement") with the FERC on January 10, 2013. If approved by the FERC, the Settlement Agreement will become effective on the date the FERC's order approving the Settlement Agreement becomes final and nonappealable. The Settlement Agreement provides that AEP would remit to Integrys Energy Services, in complete settlement of the matters at issue, a lump sum payment of $9.5 million within five business days of the effective date of the Settlement Agreement, and within five days of receipt of the lump sum payment, Integrys Energy Services would withdraw its petitions for review filed with the U.S. Court of Appeals for the D.C. Circuit.

NOTE 26—SEGMENTS OF BUSINESS

At December 31, 2012, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the regulated electric utility operations of UPPCO and WPS.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Illinois, Michigan, Minnesota, and Wisconsin.
- Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS. The operations of ITF were included in this segment beginning on September 1, 2011, when we acquired Trillium USA and Pinnacle CNG Systems.

The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
2012 (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
Income Statement								
External revenues	$1,662.1	$1,297.4	$ —	$2,959.5	$1,217.6	$35.3	$ —	$ 4,212.4
Intersegment revenues	9.9	—	—	9.9	0.9	1.9	(12.7)	—
Depreciation and amortization expense	131.8	89.0	—	220.8	10.3	20.1	(0.5)	250.7
Earnings from equity method investments	—	—	85.3	85.3	1.1	0.8	—	87.2
Miscellaneous income	0.6	2.6	—	3.2	1.1	20.9	(15.9)	9.3
Interest expense	47.3	35.9	—	83.2	2.1	50.8	(15.9)	120.2
Provision (benefit) for income taxes	61.4	49.4	32.9	143.7	25.8	(19.7)	—	149.8
Net income (loss) from continuing operations	94.0	110.4	52.4	256.8	52.6	(15.4)	—	294.0
Discontinued operations	—	—	—	—	(11.5)	1.8	—	(9.7)
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
	—	—	—	—	—	0.2	—	0.2

Noncontrolling interest in subsidiaries								
Net income (loss) attributed to common shareholders	93.4	107.9	52.4	253.7	41.1	(13.4)	—	281.4
Total assets	5,446.2	3,041.3	476.6	8,964.1	749.2	1,267.8	(653.7)	10,327.4
Cash expenditures for long-lived assets	375.1	163.9	—	539.0	30.9	24.4	—	594.3

2011 (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
Income Statement								
External revenues	$1,987.2	$1,307.3	$ —	$ 3,294.5	$1,372.0	$19.4	$ —	$ 4,685.9
Intersegment revenues	10.8	—	—	10.8	1.1	1.5	(13.4)	—
Depreciation and amortization expense	126.1	88.5	—	214.6	10.3	23.3	(0.5)	247.7
Earnings (losses) from equity method investments	—	—	79.1	79.1	(0.7)	1.0	—	79.4
Miscellaneous income	2.2	0.8	—	3.0	1.0	18.3	(17.0)	5.3
Interest expense	48.4	41.8	—	90.2	1.7	53.3	(17.0)	128.2
Provision (benefit) for income taxes	61.2	59.2	31.3	151.7	(7.7)	(10.7)	—	133.3
Net income (loss) from continuing operations	103.9	103.0	47.8	254.7	(7.1)	(17.6)	—	230.0
Discontinued operations	—	—	—	—	1.0	(0.5)	—	0.5
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Net income (loss) attributed to common shareholders	103.3	100.5	47.8	251.6	(6.1)	(18.1)	—	227.4
Total assets	5,033.0	2,982.9	439.4	8,455.3	891.5	1,215.3	(578.9)	9,983.2
Cash expenditures for long-lived assets	199.3	84.1	—	283.4	16.7	10.0	—	310.1

2010 (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
Income Statement								
External revenues	$2,056.4	$1,312.1	$ —	$ 3,368.5	$1,789.1	$12.2	$ —	$ 5,169.8
	0.8	26.8	—	27.6	1.2	—	(28.8)	—

Intersegment revenues								
Net loss on Integrys Energy Services' dispositions related to strategy change	—	—	—	—	14.1	—	—	14.1
Depreciation and amortization expense	130.9	94.7	—	225.6	11.8	23.0	—	260.4
Earnings (losses) from equity method investments	—	—	77.6	77.6	(0.4)	1.0	—	78.2
Miscellaneous income	1.6	1.5	—	3.1	9.5	40.9	(40.2)	13.3
Interest expense	49.7	43.9	—	93.6	5.5	87.8	(40.2)	146.7
Provision (benefit) for income taxes	65.3	63.1	31.4	159.8	17.7	(15.2)	—	162.3
Net income (loss) from continuing operations	84.6	112.3	46.2	243.1	24.5	(22.4)	—	245.2
Discontinued operations	—	—	—	—	(21.5)	—	—	(21.5)
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	0.3	—	—	0.3
Net income (loss) attributed to common shareholders	84.0	109.8	46.2	240.0	3.3	(22.4)	—	220.9
Total assets	4,828.1	2,929.8	416.3	8,174.2	1,234.8	1,666.7	(1,258.9)	9,816.8
Cash expenditures for long-lived assets	133.6	87.2	—	220.8	14.1	22.8	—	257.7

We had no international operating revenues for the years ended December 31, 2012, and 2011 and international operating revenues of $3.5 million for the year ended December 31, 2010. We had no international assets at December 31, 2012, 2011, and 2010.

NOTE 27—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(Millions, except share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2012					
Total revenues	$1,247.9	$839.6	$927.7	$1,197.2	$4,212.4
Operating income	153.1	87.1	108.5	118.8	467.5
Net income from continuing operations	98.8	51.7	74.3	69.2	294.0
Net income	99.7	49.6	66.3	68.7	284.3
Net income attributed to common shareholders	98.9	48.8	65.7	68.0	281.4
Earnings per common share (basic) *					
Net income from continuing operations	$1.25	$0.65	$0.94	$0.87	$3.70
Discontinued operations, net of tax	0.01	(0.03)	(0.10)	—	(0.12)
Earnings per common share (basic)	1.26	0.62	0.84	0.87	3.58
Earnings per common share (diluted) *					
Net income from continuing operations	1.24	0.65	0.93	0.86	3.67
Discontinued operations, net of tax	0.01	(0.03)	(0.10)	—	(0.12)
Earnings per common share (basic)	1.25	0.62	0.83	0.86	3.55
2011					
Total revenues	$1,620.8	$1,006.4	$931.4	$1,127.3	$4,685.9
Operating income	207.0	69.6	68.8	61.4	406.8
Net income from continuing operations	122.5	32.2	36.5	38.8	230.0
Net income	123.5	29.9	37.6	39.5	230.5
Net income attributed to common shareholders	122.7	29.1	36.9	38.7	227.4
Earnings per common share (basic) *					
Net income from continuing operations	$1.56	$0.40	$0.46	$0.48	$2.89
Discontinued operations, net of tax	0.01	(0.03)	0.01	0.01	—
Earnings per common share (basic)	1.57	0.37	0.47	0.49	2.89
Earnings per common share (diluted) *					
Net income from continuing operations	1.55	0.40	0.46	0.48	2.87
Discontinued operations, net of tax	0.01	(0.03)	0.01	0.01	—
Earnings per common share (basic)	1.56	0.37	0.47	0.49	2.87

* Earnings per share for the individual quarters do not total the year ended earnings per share amount because of changes to the average number of shares outstanding and changes in incremental issuable shares throughout the year. Earnings per share for the individual quarters differ by insignificant amounts from previously reported amounts due to the classification of certain asset groups as discontinued operations. See Note 4, "Dispositions," for more information.

Because of various factors, the quarterly results of operations are not necessarily comparable.

I. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors and Stockholders of Integrys Energy Group, Inc.:

We have audited the accompanying consolidated balance sheets of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Integrys Energy Group, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
February 28, 2013

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 December 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management Report on Internal Control over Financial Reporting

For Integrys Energy Group's Management Report on Internal Control over Financial Reporting, see Section A of Item 8.

Reports of Independent Registered Public Accounting Firm

For Integrys Energy Group's Reports of Independent Registered Public Accounting Firm, see Sections B and H of Item 8.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required by this Item regarding our directors, Section 16 compliance, and members of the Audit Committee and the Audit Committee financial expert can be found in our Proxy Statement for our Annual Meeting of Shareholders to be held May 16, 2013 (Proxy Statement), under the captions "Election of Directors," "Ownership of Voting Securities – Section 16(a) Beneficial Ownership Reporting Compliance," and "Board Committees," respectively. Such information is incorporated by reference as if fully set forth herein.

Information regarding our executive officers can be found in Item 1, "Business – Executive Officers of Integrys Energy Group."

We have a Code of Conduct, which serves as our Code of Business Conduct and Ethics. The Code of Conduct applies to all of our directors, officers, and employees, including the Chief Executive Officer, Chief Financial Officer, Corporate Controller, and any other persons performing similar functions. We have also adopted Corporate Governance Guidelines.

Our Code of Conduct, Corporate Governance Guidelines, and charters of our board committees may be accessed on our website at www.integrysgroup.com by selecting "Investors," then selecting "Corporate Governance," then selecting "Governance Documents." Amendments to, or waivers from, the Code of Conduct will be disclosed on the website within the prescribed time period.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item regarding compensation paid to our directors and our "named executive officers" in 2012 can be found in our Proxy Statement under the captions "Director Compensation," "Executive Compensation," and "Compensation Risk Assessment." Such information is incorporated by reference as if fully set forth herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this Item regarding our principal security holders and the security holdings of our directors and executive officers can be found in our Proxy Statement under the caption "Ownership of Voting Securities – Beneficial Ownership." Such information is incorporated by reference as if fully set forth herein.

Information required by this Item regarding our equity compensation plans can be found in our Proxy Statement under the caption "Ownership of Voting Securities – Equity Compensation Plan Information." Such information is incorporated by reference as if fully set forth herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this Item regarding our related person transactions and director independence can be found in our Proxy Statement under the captions "Election of Directors – Related Person Transaction Policy" and "Election of Directors – Director Independence," respectively. Such information is incorporated by reference as if fully set forth herein.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For a summary of the fees billed to us (including our subsidiaries) by Deloitte & Touche LLP for professional services performed for 2012 and 2011 and the Audit Committee's preapproval policies and procedures, please see our Proxy Statement under the caption "Board Committees – Audit Committee." Such information is incorporated by reference as if fully set forth herein.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Documents filed as part of this report:

(1) Consolidated Financial Statements included in Part II at Item 8 above:

Financial Statement Schedules.

(2) The following financial statement schedules are included in Part IV of this report. Schedules not included herein have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(3) List of all exhibits, including those incorporated by reference.

See Exhibit Index.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 28, 2013.

INTEGRYS ENERGY GROUP, INC.
(Registrant)

By: /s/ Charles A. Schrock
Charles A. Schrock
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 28, 2013.

Signature	Title
Keith E. Bailey *	Director
William J. Brodsky *	Director
Albert J. Budney, Jr. *	Director
Pastora San Juan Cafferty *	Director
Ellen Carnahan *	Director
Michelle L. Collins *	Director
Kathryn M. Hasselblad-Pascale *	Director
John W. Higgins *	Director
Paul W. Jones *	Director
Holly Keller Koeppel *	Director
Michael E. Lavin *	Director
William F. Protz, Jr. *	Director
Charles A. Schrock *	Director and Chairman
/s/ Charles A. Schrock Charles A. Schrock	Chairman, President and Chief Executive Officer (principal executive officer)
/s/ James F. Schott James F. Schott	Vice President and Chief Financial Officer (principal financial officer)
/s/ Linda M. Kallas Linda M. Kallas	Vice President and Corporate Controller (principal accounting officer)
* By: /s/ Linda M. Kallas Linda M. Kallas	Attorney-in-Fact

SCHEDULE I - CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. STATEMENTS OF INCOME

Year Ended December 31			
(Millions, except per share data)	2012	2011	2010
Equity earnings (loss) in excess of dividends from subsidiaries	$168.5	$(185.8)	$141.5
Dividends from subsidiaries	163.9	461.3	153.7
Income from subsidiaries	332.4	275.5	295.2
Investment income and other	21.2	24.2	29.9
Total income	353.6	299.7	325.1
Operating expense	6.0	5.9	6.3
Operating income	347.6	293.8	318.8
Interest expense	50.0	52.2	65.8
Income before taxes	297.6	241.6	253.0
Provision for income taxes	6.5	14.7	10.6
Net income from continuing operations	291.1	226.9	242.4
Discontinued operations from Parent Company, net of tax	1.4	(0.2)	—
Discontinued operations from subsidiaries, net of tax	(11.1)	0.7	(21.5)
Net income attributed to common shareholders	$281.4	$227.4	$220.9
Average shares of common stock			
Basic	78.6	78.6	77.5
Diluted	79.3	79.1	78.0
Earnings (loss) per common share (basic)			
Net income from continuing operations	$3.70	$2.89	$3.13
Discontinued operations, net of tax	(0.12)	—	(0.28)
Earnings per common share (basic)	$3.58	$2.89	$2.85
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$3.67	$2.87	$3.11
Discontinued operations, net of tax	(0.12)	—	(0.28)
Earnings per common share (diluted)	$3.55	$2.87	$2.83
Dividends per common share declared	$2.72	$2.72	$2.72

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (Millions)	2012	2011	2010
Net income attributed to common shareholders	281.4	227.4	220.9
Other comprehensive income (loss), net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of $0.1 million, $(0.3) million, and $(6.5) million, respectively	(0.1)	0.3	0.4
Reclassification of net losses to net income, net of tax of $(1.0) million, $0.2 million, and $4.8 million, respectively	2.1	1.1	(5.0)
Cash flow hedges, net	2.0	1.4	(4.6)
Defined benefit pension plans			
Pension and other postretirement benefit costs arising during period, net of tax of $(0.9) million, $(0.7) million, and $ – million, respectively	0.9	—	(0.4)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.4 million, $0.1 million, and $0.2 million, respectively	(0.1)	0.2	0.1
Defined benefit pension plans, net	0.8	0.2	(0.3)
Other comprehensive income (loss) from subsidiaries, net of tax	(1.2)	0.6	4.2
Other comprehensive income (loss), net of tax	1.6	2.2	(0.7)
Comprehensive income attributed to common shareholders	283.0	229.6	220.2

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

C. BALANCE SHEETS

At December 31 (Millions)	2012	2011
Assets		
Cash and cash equivalents	$2.6	$1.9
Accounts receivable from related parties	32.2	33.0
Interest receivable from related parties	4.7	4.9
Deferred income taxes	1.0	1.1
Notes receivable from related parties	34.5	22.4
Current portion of long-term receivable from related parties	72.0	—
Other current assets	39.4	70.4
Current assets	186.4	133.7
Total investments in subsidiaries, at equity	3,839.3	3,687.5
Notes receivable from related parties	171.2	243.9
Property and equipment, net of accumulated depreciation of $1.2 and $1.0, respectively	4.7	4.9
Receivables from related parties	17.3	17.8
Deferred income taxes	28.1	30.3
Other long-term assets	31.7	30.3
Total assets	$4,278.7	$4,148.4
Liabilities and Equity		
Short-term notes payable to related parties	$258.0	$181.8
Short-term debt	208.4	92.6
Current portion of long-term debt	—	100.0
Accounts payable to related parties	1.0	1.4
Interest payable to related parties	0.1	0.1
Accounts payable	0.6	1.1
Deferred income taxes	6.0	12.8
Other current liabilities	6.8	3.6
Current liabilities	480.9	393.4
Long-term notes payable to related parties	—	21.0
Long-term debt	674.7	674.6
Deferred income taxes	81.3	69.9
Payables to related parties	—	3.3
Other long-term liabilities	16.0	24.8
Long-term liabilities	772.0	793.6
Total common shareholders' equity	3,025.8	2,961.4
Total liabilities and equity	$4,278.7	$4,148.4

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

D. STATEMENTS OF CASH FLOWS

Year Ended December 31			
(Millions)	2012	2011	2010
Operating Activities			
Net income	$281.4	$227.4	$220.9
Adjustments to reconcile net income to net cash provided by operating activities			
Discontinued operations, net of tax	9.7	(0.5)	21.5
Equity (income) loss from subsidiaries, net of dividends	(168.5)	185.8	(141.5)
Deferred income taxes	8.6	29.2	44.2
Other	4.2	3.5	21.0
Changes in working capital			
Accounts receivables	0.4	(0.6)	1.4
Accounts receivables from related parties	1.0	0.9	4.4
Receivable from related parties	—	13.8	(12.9)
Other current assets	29.0	12.8	(54.5)
Accounts payable	(0.5)	—	0.4
Accounts payable to related parties	(0.4)	(5.0)	(2.0)
Other current liabilities	(3.2)	15.9	5.5
Net cash provided by operating activities	161.7	483.2	108.4
Investing Activities			
Short-term notes receivable from related parties	(12.1)	33.3	(2.6)
Long-term notes receivable from related parties	—	(10.0)	(15.0)
Receivables from related parties	0.6	0.6	(14.2)
Equity contributions to subsidiaries	(89.9)	(63.2)	(57.8)
Return of capital from subsidiaries	110.5	229.8	78.0
Proceeds from sale of investment	—	—	0.4
Other	0.7	0.7	0.7
Net cash provided by (used for) investing activities	9.8	191.2	(10.5)
Financing Activities			
Commercial paper, net	115.8	92.6	(205.1)
Short-term notes payable to related parties	76.2	(305.2)	171.3
Repayment of long-term notes payable to related parties	(21.0)	(325.0)	—
Issuance of long-term debt	—	—	250.0
Repayment of long-term debt	(100.0)	(30.2)	(65.6)
Proceeds from stock option exercises	55.8	10.3	18.8
Shares purchased for stock-based compensation	(75.3)	(9.1)	(0.9)
Issuance of common stock	—	7.3	14.6
Dividends paid on common stock	(211.9)	(206.4)	(186.1)
Other	(10.4)	(7.4)	(13.3)
Net cash used for financing activities	(170.8)	(773.1)	(16.3)
Change in cash and cash equivalents	0.7	(98.7)	81.6
Cash and cash equivalents at beginning of year	1.9	100.6	19.0
Cash and cash equivalents at end of year	$2.6	$1.9	$100.6

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

SCHEDULE I - CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

E. NOTES TO PARENT COMPANY FINANCIAL STATEMENTS

SUPPLEMENTAL NOTES

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation—For Parent Company only presentation, investments in subsidiaries are accounted for using the equity method. The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of Integrys Energy Group appearing in this Form 10-K. The consolidated financial statements of Integrys Energy Group reflect certain businesses as discontinued operations. The condensed Parent Company statements of income and statements of cash flows report the earnings and cash flows of these businesses as discontinued operations.

(b) 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 the Integrys Energy Group Parent Company Statements of Cash Flows:

(Millions)	2012	2011	2010
Cash paid for interest	$44.4	$44.6	$37.0
Cash paid for interest – related parties	1.4	6.8	20.2
Cash (received) paid for income taxes	(24.1)	(46.3)	13.6

Significant noncash transactions were:

(Millions)	2012	2011	2010
Equity issued for reinvested dividends	$—	$5.4	$22.6
Equity issued for stock-based compensation plans	—	10.6	3.0

The Issuance of common stock line item on the Parent Company Statements of Cash Flows does not agree to the Issuance of common stock line item on the Integrys Energy Group Consolidated Statements of Cash Flows. The Parent Company received cash from its subsidiaries and issued common stock to its subsidiaries to facilitate the employee stock option plan. These amounts were intercompany on the Integrys Energy Group Consolidated Statements of Cash Flows and eliminated.

NOTE 2—FAIR VALUE OF FINANCIAL INSTRUMENTS – RELATED PARTIES

The following table shows the financial instruments included on the Balance Sheets of Integrys Energy Group Parent Company that are not recorded at fair value.

(Millions)	2012 Carrying Amount	Fair Value	2011 Carrying Amount	Fair Value
Long-term notes receivable from related parties	$171.2	$202.1	$243.9	$275.6
Current portion of long-term notes receivable from related parties	72.0	73.4	—	—
Long-term notes payable to related parties	—	—	21.0	21.0

NOTE 3—SHORT-TERM NOTES RECEIVABLE – RELATED PARTIES

(Millions)	2012	2011
UPPCO	$11.9	$7.7
MERC	15.2	14.7
ITF	7.4	—
Total	$34.5	$22.4

NOTE 4—LONG-TERM NOTES RECEIVABLE – RELATED PARTIES

(Millions)	Series	Year Due	2012	2011
WPS Leasing	8.76%	2015	$2.8	$3.1
	7.35%	2016	4.4	4.8
UPPCO	5.25%	2013	15.0	15.0
	6.059%	2017	15.0	15.0
	3.35%	2018	10.0	10.0
	5.041%	2020	15.0	15.0
MERC	6.03%	2013	29.0	29.0
	6.16%	2016	29.0	29.0
	6.40%	2021	29.0	29.0
MGU	5.72%	2013	28.0	28.0
	5.76%	2016	28.0	28.0
	5.98%	2021	28.0	28.0
IBS	6.865%	2014	10.0	10.0
Total			$243.2	$243.9

NOTE 5—SHORT-TERM NOTES PAYABLE – RELATED PARTIES

(Millions)	2012	2011
Integrys Energy Services	$49.4	$27.8
PELLC	201.6	142.4
IBS	7.0	11.6
Total	$258.0	$181.8

NOTE 6—LONG-TERM NOTES PAYABLE – RELATED PARTIES

(Millions)	2012	2011
Long-term notes to Integrys Energy Services due 2021 (1)	$—	21.0
Total long-term notes payable – related parties	$—	$21.0

(1) In November 2012, Integrys Energy Group repaid the $21.0 million long-term note payable to Integrys Energy Services.

SCHEDULE II
INTEGRYS ENERGY GROUP, INC.
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts
Years Ended December 31, 2012, 2011, and 2010
(In Millions)

		Additions (Subtractions)			
Fiscal Year	Balance at Beginning of Year	Charged to Expense	Charged to Other Accounts [1]	Deductions [2]	Balance at End of Year
2010	$57.5	$48.0	$(14.1)	$49.5	$41.9
2011	$41.9	$35.0	$1.5	$31.3	$47.1
2012	$47.1	$26.2	$4.8	$34.6	$43.5

(1) Represents additions (subtractions) charged to regulatory assets and amounts charged to tax liabilities related to revenue taxes and state use taxes uncollectible from customers.

(2) Represents amounts written off to the reserve, including any adjustments.

EXHIBIT INDEX
Set forth below is a list of all exhibits to this Annual Report on Form 10-K, including those incorporated by reference.

Certain other instruments, which would otherwise be required to be listed below, have not been listed as such instruments do not authorize long-term debt securities in an amount that exceeds 10% of the total assets of us and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.
Explanatory Note: Certain exhibits listed below were entered into when we were known as WPS Resources Corporation but have been referred to below by reference to our current name.

Exhibit Number	Description of Documents
2.1*	Asset Contribution Agreement between ATC and Wisconsin Electric Power Company, Wisconsin Power and Light Company, WPS, Madison Gas & Electric Co., Edison Sault Electric Company, South Beloit Water, Gas and Electric Company, dated as of December 15, 2000. (Incorporated by reference to Exhibit 2A-3 to Integrys Energy Group's Form 10-K for the year ended December 31, 2000.)
2.2* #	Purchase and Sale Agreement between Integrys Energy Services, Inc., as Seller, and Macquarie Cook Power, Inc., as Purchaser, dated as of December 23, 2009. (Incorporated by reference to Exhibit 2.2 to Integrys Energy Group’s Form 10-K/A filed April 23, 2010.)
2.3#	First Amendment to Purchase and Sale Agreement dated January 26, 2010, between Integrys Energy Services, Inc., as Seller, and Macquarie Cook Power, Inc., as Purchaser. (Incorporated by reference to Exhibit 2.3 to Integrys Energy Group’s Form 10-K/A filed April 23, 2010.)
3.1	Restated Articles of Incorporation of Integrys Energy Group, as amended. (Incorporated by reference to Exhibit 3.2 to Integrys Energy Group's Form 8-K filed May 16, 2012.)
3.2	By-Laws of Integrys Energy Group, as amended through May 10, 2012. (Incorporated by reference to Exhibit 3.4 to Integrys Energy Group's Form 8-K filed May 16, 2012.)
4.1	Senior Indenture, dated as of October 1, 1999, between Integrys Energy Group and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4(b) to Amendment No. 1 to Form S-3 filed October 21, 1999 [Reg. No. 333-88525]); First Supplemental Indenture, dated as of November 1, 1999 between Integrys Energy Group and Firstar Bank, National Association (Incorporated by reference to Exhibit 4A of Form 8-K filed November 12, 1999); Second Supplemental Indenture, dated as of November 1, 2002 between Integrys Energy Group and U.S. Bank National Association (Incorporated by reference to Exhibit 4A of Form 8-K filed November 25, 2002); Third Supplemental Indenture, dated as of June 1, 2009, by and between Integrys Energy Group and U.S. Bank National Association (Incorporated by reference to Exhibit 4.1 to Integrys Energy Group’s Form 8-K filed June 17, 2009); Fourth Supplemental Indenture, dated as of June 1, 2009, by and between Integrys Energy Group (Incorporated by reference to Exhibit 4.2 to Integrys Energy Group’s Form 8-K filed June 17, 2009); and Fifth Supplemental Indenture, dated as of November 1, 2010, by and between Integrys Energy Group and U.S. Bank National Association (Incorporated by reference to Exhibit 4 to Integrys Energy Group’s Form 8-K filed November 15, 2010). All references to filings are those of Integrys Energy Group.
4.2	Subordinated Indenture, dated as of November 13, 2006, between Integrys Energy Group and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4(c) to Amendment No. 1 to Form S-3 filed December 4, 2006 [Reg. No. 333 133194]; and First Supplemental Indenture by and between

	Integrys Energy Group, Inc. and U.S. Bank National Association, as trustee, dated December 1, 2006. (Incorporated by reference to Exhibit 4 to Integrys Energy Group's Form 8-K filed December 1, 2006.)
4.3	Replacement Capital Covenant of Integrys Energy Group, Inc., dated December 1, 2010. (Incorporated by reference to Exhibit 99.1 to Integrys Energy Group Form 8-K filed November 15, 2010.)

116

4.4	First Mortgage and Deed of Trust, dated as of January 1, 1941, from WPS to U.S. Bank National Association (successor to First Wisconsin Trust Company), Trustee (Incorporated by reference to Exhibit 7.01 - File No. 2-7229); Supplemental Indenture, dated as of November 1, 1947 (Incorporated by reference to Exhibit 7.02 - File No. 2-7602); Supplemental Indenture, dated as of November 1, 1950 (Incorporated by reference to Exhibit 4.04 - File No. 2-10174); Supplemental Indenture, dated as of May 1, 1953 (Incorporated by reference to Exhibit 4.03 - File No. 2-10716); Supplemental Indenture, dated as of October 1, 1954 (Incorporated by reference to Exhibit 4.03 - File No. 2-13572); Supplemental Indenture, dated as of December 1, 1957 (Incorporated by reference to Exhibit 4.03 - File No. 2-14527); Supplemental Indenture, dated as of October 1, 1963 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of June 1, 1964 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of November 1, 1967 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Supplemental Indenture, dated as of April 1, 1969 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Fifteenth Supplemental Indenture, dated as of May 1, 1971 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Sixteenth Supplemental Indenture, dated as of August 1, 1973 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Seventeenth Supplemental Indenture, dated as of September 1, 1973 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Eighteenth Supplemental Indenture, dated as of October 1, 1975 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Nineteenth Supplemental Indenture, dated as of February 1, 1977 (Incorporated by reference to Exhibit 2.02B - File No. 2-65710); Twentieth Supplemental Indenture, dated as of July 15, 1980 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1980); Twenty-First Supplemental Indenture, dated as of December 1, 1980 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1980); Twenty-Second Supplemental Indenture dated as of April 1, 1981 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1981); Twenty-Third Supplemental Indenture, dated as of February 1, 1984 (Incorporated by reference to Exhibit 4B to Form 10-K for the year ended December 31, 1983); Twenty-Fourth Supplemental Indenture, dated as of March 15, 1984 (Incorporated by reference to Exhibit 1 to Form 10-Q for the quarter ended June 30, 1984); Twenty-Fifth Supplemental Indenture, dated as of October 1, 1985 (Incorporated by reference to Exhibit 1 to Form 10-Q for the quarter ended September 30, 1985); Twenty-Sixth Supplemental Indenture, dated as of December 1, 1987 (Incorporated by reference to Exhibit 4A-1 to Form 10-K for the year ended December 31, 1987); Twenty-Seventh Supplemental Indenture, dated as of September 1, 1991 (Incorporated by reference to Exhibit 4 to Form 8-K filed September 18, 1991); Twenty-Eighth Supplemental Indenture, dated as of July 1, 1992 (Incorporated by reference to Exhibit 4B - File No. 33-51428); Twenty-Ninth Supplemental Indenture, dated as of October 1, 1992 (Incorporated by reference to Exhibit 4 to Form 8-K filed October 22, 1992); Thirtieth Supplemental Indenture, dated as of February 1, 1993 (Incorporated by reference to Exhibit 4 to Form 8-K filed January 27, 1993); Thirty-First Supplemental Indenture, dated as of July 1, 1993 (Incorporated by reference to Exhibit 4 to Form 8-K filed July 7, 1993); Thirty-Second Supplemental Indenture, dated as of November 1, 1993 (Incorporated by reference to Exhibit 4 to Form 10-Q for the quarter ended September 30, 1993); Thirty-Third Supplemental Indenture, dated as of December 1, 1998 (Incorporated by reference to Exhibit 4D to Form 8-K filed December 18, 1998); Thirty-Fourth Supplemental Indenture, dated as of August 1, 2001 (Incorporated by reference to Exhibit 4D to Form 8-K filed August 24, 2001); Thirty-Fifth Supplemental Indenture, dated as of December 1, 2002 (Incorporated by reference to Exhibit 4D to Form 8-K filed December 16, 2002); Thirty-Sixth Supplemental Indenture, dated as of December 8, 2003 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed December 9, 2003); Thirty-Seventh Supplemental Indenture, dated as of December 1, 2006 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 30, 2006); Thirty-Eighth Supplemental Indenture, dated as of August 1, 2006 (Incorporated by reference to Exhibit 4.1 to Form 10-K for the year ended December 31, 2006); Thirty-Ninth Supplemental Indenture, dated as of November 1, 2007 (Incorporated by reference to

	Exhibit 4.2 to Form 8-K filed November 16, 2007); Fortieth Supplemental Indenture, dated as of December 1, 2008 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed December 4, 2008); Forty-First Supplemental Indenture, dated as of December 18, 2008 (Incorporated by reference to Exhibit 4.1 to Form 10-Q filed May 6, 2010); 42nd Supplemental Indenture, dated as of April 25, 2010 (Incorporated by reference to Exhibit 4.2 to Form 10-Q filed May 6, 2010); and 43rd Supplemental Indenture, dated as of December 1, 2012 (Incorporated by reference to Exhibit 4.2 to Form 8-K filed November 29, 2012). All references to periodic reports are to those of WPS (File No. 1-3016).
4.5	Indenture, dated as of December 1, 1998, between WPS and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4A to Form 8-K filed December 18, 1998); First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firstar Bank Milwaukee, N.A., National Association (Incorporated by reference to Exhibit 4C to Form 8-K filed December 18, 1998); Second Supplemental Indenture, dated as of August 1, 2001, between WPS and Firstar Bank, National Association (Incorporated by reference to Exhibit 4C of Form 8-K filed August 24, 2001); Third Supplemental Indenture, dated as of December 1, 2002, between WPS and U.S. Bank National Association (Incorporated by reference to Exhibit 4C of Form 8-K filed December 16, 2002); Fourth Supplemental Indenture, dated as of December 8, 2003, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed December 9, 2003); Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 30, 2006); Sixth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.2 to Form 10-K for the year ended December 31, 2006); Seventh Supplemental Indenture, dated as of November 1, 2007, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 16, 2007); Eighth Supplemental Indenture, dated as of December 1, 2008, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed December 4, 2008); and Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (successor to Firstar Bank, National Association and Firstar Bank Milwaukee, N.A., National Association) (Incorporated by reference to Exhibit 4.1 to Form 8-K filed November 29, 2012). References to periodic reports are to those of WPS (File No. 1-3016).

4.6	PGL First and Refunding Mortgage, dated January 2, 1926, from Chicago By-Product Coke Company to Illinois Merchants Trust Company, Trustee, assumed by PGL by Indenture dated March 1, 1928 (PGL - May 17, 1935, Exhibit B-6a, Exhibit B-6b A-2 File No. 2-2151, 1936); Supplemental Indenture dated as of May 20, 1936, (PGL - Form 8-K for the year 1936, Exhibit B-6f); Supplemental Indenture dated as of March 10, 1950 (PGL - Form 8-K for the month of March 1950, Exhibit B-6i); Supplemental Indenture dated as of June 1, 1951 (PGL - File No. 2-8989, Post-Effective, Exhibit 7-4(b)); Supplemental Indenture dated as of August 15, 1967 (PGL - File No. 2-26983, Post-Effective, Exhibit 2-4); Supplemental Indenture dated as of September 15, 1970 (PGL - File No. 2-38168, Post-Effective Exhibit 2-2); Supplemental Indenture dated June 1, 1995 (PGL - Form 10-K for fiscal year ended September 30, 1995); Supplemental Indenture, First and Refunding Mortgage Multi-Modal Bonds, Series HH of PGL, effective March 1, 2000 (PGL - Form 10-K for fiscal year ended September 30, 2000, Exhibit 4(b)); Supplemental Indenture dated as of February 1, 2003, First and Refunding Mortgage 5% Bonds, Series KK (PELLC and PGL - Form 10-Q for the quarter ended March 31, 2003, Exhibit 4(a)); Supplemental Indenture dated as of February 1, 2003, First and Refunding Mortgage Multi-Modal Bonds, Series LL (PELLC and PGL - Form 10-Q for the quarter ended March 31, 2003, Exhibit 4(b)); Supplemental Indenture dated as of February 15, 2003, First and Refunding Mortgage 4.00% Bonds, Series MM-1 and Series MM-2 (PELLC and PGL - Form 10-Q for the quarter ended March 31, 2003, Exhibit 4(c)); Supplemental Indenture dated as of April 15, 2003, First and Refunding Mortgage 4.625% Bonds, Series NN-1 and Series NN-2 (PELLC and PGL - Form 10-Q for the quarter ended March 31, 2003, Exhibit 4(e)); Supplemental Indenture dated as of October 1, 2003, First and Refunding Mortgage Bonds, Series OO (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(a)); PGL Supplemental Indenture dated as of October 1, 2003, First and Refunding Mortgage Bonds, Series PP (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(b)); PGL Supplemental Indenture dated as of November 1, 2003, First and Refunding Mortgage Multi-Modal Bonds, Series QQ (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(c)); PGL Supplemental Indenture dated as of January 1, 2005, First and Refunding Mortgage Bonds, Series RR (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2004, Exhibit 4(b)); Loan Agreement between PGL and Illinois Development Finance Authority dated October 1, 2003, Gas Supply Refunding Revenue Bonds, Series 2003C (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(d)); Loan Agreement between PGL and Illinois Development Finance Authority dated October 1, 2003, Gas Supply Refunding Revenue Bonds, Series 2003D (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(e)); Loan Agreement between PGL and Illinois Development Finance Authority dated November 1, 2003, Gas Supply Refunding Revenue Bonds, Series 2003E (PELLC and PGL - Form 10-Q for the quarter ended December 31, 2003, Exhibit 4(f)); Loan Agreement between PGL and Illinois Finance Authority dated as of January 1, 2005 (incorporated by reference to Exhibit 4(a) to PELLC Form 10-Q filed February 9, 2005); Supplemental Indenture dated as of November 1, 2008, First and Refunding Mortgage 7.00% Bonds, Series SS (incorporated by reference to Exhibit 4.11 to Integrys Energy Group's Form 10-K for the year ended December 31, 2008); Supplemental Indenture dated as of November 1, 2008, First and Refunding Mortgage 8.00% Bonds, Series TT (incorporated by reference to Exhibit 4.11 to Integrys Energy Group's Form 10-K for the year ended December 31, 2008); Supplemental Indenture dated as of September 1, 2009, First and Refunding Mortgage 4.63% Bonds, Series UU (incorporated by reference to Exhibit 4.11 to Integrys Energy Group's Form 10-K/A filed April 23, 2010); Supplemental Indenture dated as of August 1, 2010, First and Refunding Mortgage 2.125% Bonds, Series VV; Supplemental Indenture dated as of October 1, 2010, First and Refunding Mortgage 2.625% Bonds, Series WW; Supplemental Indenture dated as of November 1, 2011, First and Refunding Mortgage 2.21% Bonds, Series XX; and Supplemental Indenture dated as of December, 4, 2012, First and Refunding Mortgage 3.98% Bonds, Series YY.

4.7	NSG Indenture, dated as of April 1, 1955, from NSG to Continental Bank, National Association, as Trustee; Third Supplemental Indenture, dated as of December 20, 1963 (NSG - File No. 2-35965, Exhibit 4-1); Fourth Supplemental Indenture, dated as of May 1, 1964 (NSG - File No. 2-35965, Exhibit 4-1); Fifth Supplemental Indenture dated as of February 1, 1970 (NSG - File No. 2-35965, Exhibit 4-2); Ninth Supplemental Indenture dated as of December 1, 1987 (NSG - Form 10-K for the fiscal year ended September 30, 1987, Exhibit 4); Thirteenth Supplemental Indenture dated December 1, 1998 (NSG Gas - Form 10-Q for the quarter ended March 31, 1999, Exhibit 4); Fourteenth Supplemental Indenture dated as of April 15, 2003, First Mortgage 4.625% Bonds, Series N-1 and Series N-2 (Incorporated by reference to Exhibit 4(g) to PELLC Form 10-Q filed May 13, 2003); Fifteenth Supplemental Indenture dated as of November 1, 2008, First Mortgage 7.00% Bonds, Series O (Incorporated by reference to Exhibit 4.12 to Integrys Energy Group’s Form 10-K for the year ended December 31, 2008); and Sixteenth Supplemental Indenture dated as of April 3, 2012, First Mortgage 3.43% Bonds, Series P.
10.1+	Form of Key Executive Employment and Severance Agreement entered into between Integrys Energy Group and Phillip M. Mikulsky. (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group’s Form 10-K for the year ended December 31, 2008.)
10.2+	Form of Key Executive Employment and Severance Agreement entered into between Integrys Energy Group and each of the following: Charles A. Schrock, Joseph P. O'Leary, Mark A. Radtke, Lawrence T. Borgard, and Daniel J. Verbanac. (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group’s Form 8-K filed May 12, 2010.)
10.3+	Integrys Energy Group Executive Change in Control Severance Plan applicable to the following: William D. Laakso and James F. Schott. (Incorporated by reference to Exhibit 10.3 to Integrys Energy Group's Form 10-K for the year ended December 31, 2010.)
10.4+	Form of Integrys Energy Group 2005 Omnibus Incentive Compensation Plan Performance NonQualified Stock Option Agreement approved December 7, 2005. (Incorporated by reference to Exhibit 10.1 to Integrys Energy Group's Form 8-K filed December 13, 2005.)
10.5+	Form of Integrys Energy Group 2005 Omnibus Incentive Compensation Plan Performance NonQualified Stock Option Agreement approved December 7, 2006. (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group's Form 8-K filed December 13, 2006.)
10.6+	Form of Integrys Energy Group 2007 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved May 17, 2007. (Incorporated by reference to Exhibit 10.10 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.7+	Form of Integrys Energy Group 2007 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement approved February 14, 2008. (Incorporated by reference to Exhibit 10.9 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.8+	Form of Integrys Energy Group 2007 Omnibus Incentive Compensation Plan NonQualified Stock Option Agreement approved February 14, 2008. (Incorporated by reference to Exhibit 10.11 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.9+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Performance Stock Right Agreement approved September 16, 2010. (Incorporated by reference to Exhibit 10.3 to Integrys Energy Group’s Form 8-K filed September 22, 2010.)
10.10+	

	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement approved September 16, 2010. (Incorporated by reference to Exhibit 10.4 to Integrys Energy Group's Form 8-K filed September 22, 2010.)
10.11+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Nonqualified Stock Option Agreement approved September 16, 2010. (Incorporated by reference to Exhibit 10.5 to Integrys Energy Group's Form 8-K filed September 22, 2010.)
10.12+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Performance Stock Right Agreement approved December 13, 2012.
10.13+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement approved December 13, 2012.

10.14+	Form of Integrys Energy Group, Inc. 2010 Omnibus Incentive Compensation Plan Nonqualified Stock Option Agreement approved December 13, 2012.
10.15+	Integrys Energy Group, Inc. Deferred Compensation Plan, as Amended and Restated Effective January 1, 2012. (Incorporated by reference to Exhibit 10.17 to Integrys Energy Group's Form 10-K for the year ended December 31, 2011, filed February 29, 2012.)
10.16+	Integrys Energy Group, Inc. Pension Restoration and Supplemental Retirement Plan, as Amended and Restated Effective January 1, 2011. (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group’s Form 8-K filed September 22, 2010.)
10.17+	Integrys Energy Group 2001 Omnibus Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.16 to Integrys Energy Group's Form 10-K for the year ended December 31, 2005, filed February 28, 2006.)
10.18+	Integrys Energy Group 2005 Omnibus Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2 to Integrys Energy Group's Form 10-Q filed August 4, 2005.)
10.19+	Integrys Energy Group 2007 Omnibus Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.17 to Integrys Energy Group's Form 10-K for the year ended December 31, 2007.)
10.20+	Integrys Energy Group 2010 Omnibus Incentive Compensation Plan, as amended. (Incorporated by reference to Exhibit 10.22 to Integrys Energy Group's Form 10-K for the year ended December 31, 2011, filed February 29, 2012.)
10.21+	PELLC Directors Stock and Option Plan as amended December 4, 2002. (Incorporated by reference to Exhibit 10(g) to PELLC Form 10-Q, filed February 11, 2003 [File No. 1-05540].)
10.22+	PELLC Directors Deferred Compensation Plan as amended and restated April 7, 2004. (Incorporated by reference to Exhibit 10(a) to PELLC Form 10-Q filed August 4, 2005.)
10.23+	PELLC Executive Deferred Compensation Plan amended as of December 4, 2002. (Incorporated by reference to Exhibit 10(c) to PELLC Form 10-Q filed February 11, 2003.)
10.24+	PELLC 1990 Long-Term Incentive Compensation Plan as amended December 4, 2002. (Incorporated by reference to Exhibit 10(d) to Quarterly Report on Form 10-Q of PELLC for the quarterly period ended December 31, 2002, filed February 11, 2003 [File No. 1-05540].)
10.25+	Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of August 13, 2003. (Incorporated by reference to Exhibit 10(a) to PELLC Form 10-K for the fiscal year ended September 30, 2003.)
10.26+	Amendment Number One to the Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of July 24, 2006. (Incorporated by reference to Exhibit 10(e) to PELLC Form 10-K for the fiscal year ended September 30, 2006.)
10.27	

	Five Year Credit Agreement with The Bank of Tokyo-Mitsubishi UFJ, Ltd.; Union Bank, N.A.; JPMorgan Chase Bank, N.A.; KeyBank National Association; Mizuho Corporate Bank Ltd.; The Bank of Nova Scotia; U.S. Bank National Association; and J.P. Morgan Securities LLC, dated as of June 13, 2012. (Incorporated by reference to Exhibit 10 to Integrys Energy Group's Form 8-K filed June 19, 2012.)
10.28	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.)
10.29	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.)
10.30* #	Joint Plant Agreement by and between WPS and Dairyland Power Cooperative, dated as of November 23, 2004. (Incorporated by reference to Exhibit 10.19 to Integrys Energy Group's and WPS's Form 10-K for the year ended December 31, 2004.)
21	Subsidiaries of Integrys Energy Group.
23.1	Consent of Independent Registered Public Accounting Firm for Integrys Energy Group.
23.2	Consent of Independent Registered Public Accounting Firm for American Transmission Company LLC.
24	Power of Attorney.
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.
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.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group.
99.1	Proxy Statement for Integrys Energy Group's 2013 Annual Meeting of Shareholders. [To be filed with the SEC under Regulation 14A within 120 days after December 31, 2012; except to the extent specifically incorporated by reference, the Proxy Statement for the 2013 Annual Meeting of Shareholders shall not be deemed to be filed with the SEC as part of this Annual Report on Form 10-K.]
99.2	Financial Statements of American Transmission Company LLC.
101	Financial statements from the Annual Report on Form 10-K of Integrys Energy Group, Inc. for the year ended December 31, 2012, filed on March 1, 2013 formatted in eXtensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income; (ii) the Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Equity; (v) the Consolidated Statements of Cash Flows; and (v) the Notes to Consolidated Financial Statements; and (vi) document and entity information.

* Schedules and exhibits to this document are not filed therewith. The registrant agrees to furnish supplementally a copy of any such schedule or exhibit to the SEC upon request.

\+ A management contract or compensatory plan or arrangement.

\# Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of SEC pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934, as amended. The redacted material was filed separately with the SEC.