INTEGRYS ENERGY GROUP, INC.
Form 10-K
February 29, 2012
Table of Contents

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, 2011

OR

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

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-11337	**INTEGRYS ENERGY GROUP, INC.** (A Wisconsin Corporation) 130 East Randolph Street Chicago, 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 o

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 o 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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 o

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. o

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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

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

$4,039,305,304 as of June 30, 2011

Number of shares outstanding of each class of common stock, as of February 24, 2012

Common Stock, $1 par value, 78,287,906 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 10, 2012 are incorporated by reference into Part III.

Table of Contents

INTEGRYS ENERGY GROUP, INC.

ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2011

TABLE OF CONTENTS

Table of Contents

Table of Contents

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
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
ICR	Infrastructure Cost Recovery
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

Table of Contents

Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions, but rather are subject to numerous management assumptions, risks, and uncertainties. Therefore, actual results may differ materially from those expressed or implied by these statements. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot provide assurance that such statements will prove correct.

Forward-looking statements involve a number of risks and uncertainties. Some risks that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2011 and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting coal-fired generation facilities and renewable energy standards;
- Other federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims, including manufactured gas plant site cleanup, third-party intervention in permitting and licensing projects, compliance with Clean Air Act requirements at generation plants, and prudence and reconciliation of costs recovered in revenues through automatic gas cost recovery mechanisms;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries liquidity and financing efforts;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;
- The ability to retain market-based rate authority;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;

- The impact of unplanned facility outages;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer use, customer growth, and our ability to adequately forecast energy use for all of our customers;
- Potential business strategies, including mergers, acquisitions, and construction or disposition of assets or businesses, which cannot be assured to be completed timely or within budgets;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries counterparties, affiliates, and customers to meet their obligations;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The ability to use tax credit and loss carryforwards;
- The financial performance of ATC and its corresponding contribution to our earnings;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file with the SEC.

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

Table of Contents

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 t 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 27, *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 with regulated natural gas and electric utility operations, nonregulated energy operations, and an approximate 34% equity ownership interest in ATC, a regulated electric transmission company. We were incorporated in Wisconsin in 1993.

Natural Gas Utility Segment

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

Electric Utility Segment

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

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 to commercial, industrial, and residential customers in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.

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 9, *Investments in Affiliates, at Equity Method*, for more information about ATC.

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 4, *Acquisition*, for more information about the acquisition of Trillium and Pinnacle.

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.

Table of Contents

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 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 regulated natural gas utilities provide service to approximately 1,682,000 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.

Facilities

For information regarding our regulated natural gas facilities, see Item 2, *Properties*. For our utility plant asset book value, see Note 6, *Property, Plant, and Equipment*.

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 16, *Commitments and Contingencies*.

Our regulated natural gas utilities own two storage fields and contract with various 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 which can lead to favorable conditions when negotiating new agreements for transportation and storage services. In addition, our regulated natural gas utilities use financial instruments such as commodity futures, swaps, and options as part of their hedging program to further reduce supply cost volatility.

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 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.

Set forth below is a rollforward of 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)	**2011**	**2010**	**2009**
Beginning Balance, January 1	**5,156**	**5,187**	4,541
Injections	**7,000**	**7,010**	6,978
Withdrawals	**(6,895)**	**(7,041)**	(6,332)
Ending Balance, December 31	**5,261**	**5,156**	5,187

(Millions)	**2011**	**2010**	**2009**
Natural gas hub service fees	**$ 5.4**	**$ 10.3**	$ 5.8

Table of Contents

Our regulated natural gas utilities had adequate capacity to meet all firm natural gas demand obligations during 2011 and expect to have adequate capacity to meet all firm obligations during 2012. Our regulated natural gas utilities forecast design peak-day throughput is 3,736 MDth for the 2011 through 2012 heating season.

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

(MDth)	2011	2010	2009
Natural gas purchases	**217,288**	204,794	224,762
Natural gas purchases for electric generation	**1,780**	1,389	957
Customer-owned natural gas received	**181,021**	172,180	164,676
Underground storage, net	**(1,425)**	3,494	1,080
Hub fuel in kind *	**180**	176	141
Liquefied petroleum gas (propane)	**1**	4	12
Owned storage cushion injection	**(1,098)**	(1,094)	(1,272)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted- for natural gas	**(10,809)**	(7,544)	(9,692)
Total	**386,938**	373,399	380,664

* 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 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 directly through to customers in 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. 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 26, *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 2011, the regulated natural gas utility segment recorded approximately 64% of its revenues in January, February, March, November, and December.

Table of Contents

Competition

Although our natural gas retail rates are regulated by various commissions, the utilities still face competition from other entities and forms of energy 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. Such 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 our transportation customers now purchase from the 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. Additionally, some customers have elected to purchase their natural gas directly from one of our regulated natural gas utilities on an interruptible basis, as a means to reduce their 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 the 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 affiliates and 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

Our regulated electric utility operations of WPS and UPPCO provide service to approximately 493,000 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 any wholesale electric customers due to the expiration of its remaining wholesale electric contracts in 2011. In 2011, retail electric revenues accounted for 82.9% of total electric revenues, while wholesale electric revenues accounted for 17.1% of total electric revenues.

In 2011, WPS reached a firm net design peak of 2,344 megawatts (MW) on July 20. At the time of this summer peak, WPS s total firm resources (i.e., generation plus firm purchases) totaled 3,164 MW. 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 17.4% reserve margin requirement from January 1 through May 31, 2012, and 14.4% for the remainder of 2012. The MPSC does not have minimum guidelines for future supply reserves.

In 2011, UPPCO reached a firm net design peak of 121 MW on February 18. At the time of this peak, UPPCO s total firm resources totaled 148 MW. 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 2012. WPS and UPPCO had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2011 and expect to have adequate capacity to meet all obligations during 2012.

Facilities

For a complete list of our electric utility facilities, see Item 2, *Properties*. For our utility plant asset book value, see Note 6, *Property, Plant, and Equipment*.

Table of Contents

Electric Supply

Both WPS and UPPCO are members of MISO, a FERC-approved, independent, non-profit 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)**	**2011**	**2010**	**2009**
Company-owned generation units			
Coal	**8,634.5**	10,232.9	8,974.3
Hydroelectric	**348.9**	306.5	225.9
Wind	**309.3**	287.7	46.4
Natural gas, fuel oil, and tire derived	**135.8**	105.4	71.4
Total company-owned generation units	**9,428.5**	10,932.5	9,318.0
Power purchase contracts			
Nuclear (Kewaunee Power Station)	**2,674.4**	2,940.8	2,663.9
Natural gas (Fox Energy Center, LLC and Combined Locks Energy Center, LLC)	**1,593.9**	608.4	673.7
Hydroelectric	**570.7**	526.7	569.5
Wind	**210.6**	149.1	136.9
Other	**235.8**	205.5	571.1
Total power purchase contracts	**5,285.4**	4,430.5	4,615.1
Purchased power from MISO	**1,605.2**	781.9	1,898.9
Purchased power from other	**100.1**	342.9	54.4
Total purchased power	**6,990.7**	5,555.3	6,568.4
Opportunity sales			
Sales to MISO	**(1,242.0)**	(734.5)	(462.5)
Net sales to other	**(64.6)**	(248.4)	(450.5)
Total opportunity sales	**(1,306.6)**	(982.9)	(913.0)
Total electric utility supply	**15,112.6**	15,504.9	14,973.4

Fuel Costs

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

Fuel Type	2011	2010	2009
Coal	**$ 2.44**	$ 2.05	$ 1.94
Natural gas	**5.64**	6.28	6.73
Fuel oil	**21.24**	18.44	17.09

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 their share of the coal costs. Wisconsin Power and Light 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, 2011, WPS had coal transportation contracts in place for 100% of its 2012 coal transportation requirements. For more information on coal purchases and coal deliveries under contract, see Note 16, *Commitments and Contingencies*.

Table of Contents

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 16, *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 26, *Regulatory Environment*, for information regarding 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. However, an active competitive market has not yet developed in the Upper Peninsula of Michigan, primarily due to a lack of excess generation and transmission system capacity.

D. INTEGRYS ENERGY SERVICES

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.

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 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.

Table of Contents

Recent Developments

Throughout 2009 and 2010, Integrys Energy Services was repositioned to focus on serving retail natural gas and retail electric customers concentrated in the northeast quadrant of the United States, and investing in energy assets with renewable attributes. 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.

In October 2010, Integrys Energy Services announced the launch of 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 will equally fund the necessary equity capital for construction and ownership of the solar projects, and are considering pursuing financing to be secured by the joint venture. See Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Future Capital Requirements and Resources*, for estimated construction expenditures for Integrys Energy Services.

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.

Facilities

For information regarding the energy asset facilities owned by Integrys Energy Services, see Item 2, *Properties*. For our nonregulated plant asset book value, see Note 6, *Property, Plant, and Equipment*.

Fuel Supply for Generation Facilities

Integrys Energy Services fuel inventory policy varies for each generation facility depending on the type of fuel used. The natural gas-fired facilities (78.0% 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. The Westwood facility (12.2% of its installed generation portfolio) burns waste coal left behind by mining operations and has several years supply on site. All fuel is located within a seven-mile radius of the facility. The renewable energy facilities (9.8% 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, 2011, Integrys Energy Services largest retail electric markets included the Illinois, New York, New England, Mid-Atlantic, and Michigan regions. Integrys Energy Services largest retail natural gas markets included Wisconsin, Illinois, Ohio, and Michigan. 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 the appropriate rate of return, and currently has no plans to expand into new geographic regions. 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 paper and allied products, general government and national security, food and kindred products, schools (including primary, secondary, colleges, and universities), chemicals and paint, and steel and foundries.

Table of Contents

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, with the first and fourth quarters, in the aggregate, typically being 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, 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 than 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.

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 debt (both long-term and short-term). As of December 31, 2011, Integrys Energy Services had the ability to borrow up to $765.0 million through an intercompany credit facility with us. As of December 31, 2011, we have provided total parental guarantees of $532.0 million on behalf of Integrys Energy Services, which includes guarantees for the current retail business as well as residual guarantees related to assets sold in 2009 and 2010.

E. ENVIRONMENTAL MATTERS

For information on our environmental matters, see Note 16, *Commitments and Contingencies*.

F. 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*.

Table of Contents

G. EMPLOYEES

At December 31, 2011, our consolidated subsidiaries had the following employees:

	Total Number of Employees	Percentage of Employees Covered by Collective Bargaining Agreements
WPS	**1,304**	**69%**
IBS	**1,252**	
PGL	**1,077**	**79%**
Integrys Energy Services	**276**	
MERC	**217**	**20%**
NSG	**163**	**80%**
MGU	**157**	**69%**
UPPCO	**115**	**82%**
ITF	**58**	
Total	**4,619**	**46%**

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

Union	Subsidiary	Contract Expiration Date
Local 310 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	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

Table of Contents

H. EXECUTIVE OFFICERS OF INTEGRYS ENERGY GROUP

Name and Age (1)		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	58	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
		President and Chief Operating Officer Generation WPS	08-15-04
Lawrence T. Borgard	50	President and Chief Operating Officer Utilities	04-05-09
		President and Chief Operating Officer Integrys Gas Group (2)	02-21-07
		President and Chief Operating Officer Energy Delivery WPS	08-15-04
Phillip M. Mikulsky	63	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
		Executive Vice President Development	09-12-04
Mark A. Radtke	50	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	57	Senior Vice President and Chief Financial Officer	06-04-01
Diane L. Ford	58	Vice President and Corporate Controller	02-21-07
		Vice President Controller and Chief Accounting Officer	07-11-99
William J. Guc	42	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	49	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
		Director of Organizational Development WPS	12-12-05
James F. Schott	54	Vice President External Affairs	03-22-10
		Vice President Regulatory Affairs	07-18-04
Barth J. Wolf	54	Vice President, Chief Legal Officer and Secretary	07-31-07
		Vice President Legal Services and Chief Compliance Officer IBS	02-21-07
		Secretary and Manager Legal Services	09-19-99
Daniel J. Verbanac	48	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 December 31, 2011. 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 includes PGL, NSG, MERC, and MGU.

Table of Contents

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, which our regulated utilities are allowed to charge for their 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 the 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, and non-compliance 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.

Table of Contents

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 has adopted regulations under the Clean Air Act (CAA) that apply to permitting new or significantly modified facilities. The EPA also announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. 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 coal-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 and seasonality;
- 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 power plants and distribution system, 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 as a result of selling less electric energy, including having to operate our higher cost electric generators or obtaining 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.

Table of Contents

Our operations are subject to risks beyond our control, including but not limited to, cyber security attacks, terrorist attacks, acts of war, or loss of 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. The cost of repairing damage to our facilities or for legal claims caused by these attacks may not be recoverable in rates or may exceed the insurance limits on our insurance policies or, in some cases, may not be covered by insurance. The high cost or potential unavailability of insurance to cover terrorist activity may also adversely impact our results of operations and financial conditions.

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.

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 is dependent 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.

Table of Contents

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 remain in effect for any given period of time or that a credit rating 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.

Table of Contents

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 non-utility 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 Law 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.

Table of Contents

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, 2011:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)
Steam	Columbia Units 1 and 2	Portage, WI	Coal	349.6(2)
	Edgewater Unit 4	Sheboygan, WI	Coal	98.1(2)
	Pulliam (4 units)	Green Bay, WI	Coal	328.4
	Weston Units 1, 2, and 3	Marathon County, WI	Coal	458.9
	Weston Unit 4	Marathon County, WI	Coal	382.5(2)
Total Steam				1,617.5
Combustion Turbine and Diesel	De Pere Energy Center	De Pere, WI	Natural Gas	163.6
	Gladstone	Gladstone, MI	Oil	18.4
	Juneau #31	Adams County, WI	Distillate Fuel Oil	6.3(2)
	Pulliam #31	Green Bay, WI	Natural Gas	85.0
	West Marinette #31	Marinette, WI	Natural Gas	38.3
	West Marinette #32	Marinette, WI	Natural Gas	34.1
	West Marinette #33	Marinette, WI	Natural Gas	77.7
	Weston #31	Marathon County, WI	Natural Gas	17.4
	Weston #32	Marathon County, WI	Natural Gas	46.9
Total Combustion Turbine and Diesel				487.7
Hydroelectric	Various	Michigan	Hydro	19.4
	Various	Wisconsin	Hydro	67.6(3)
Total Hydroelectric				87.0
Wind	Lincoln	Wisconsin	Wind	1.1
	Crane Creek	Iowa	Wind	19.5
Total Wind				20.6
Total System				2,212.8

(1) Based on capacity ratings for July 2012, 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 66.7% of total capacity at Castle Rock and Petenwell. WPS s share of capacity for Castle Rock is 11.7 megawatts, and WPS s share of capacity for Petenwell is 13.9 megawatts.

As of December 31, 2011, our electric utilities owned approximately 25,000 miles of electric distribution lines located in Michigan and Wisconsin and approximately 180 distribution substations.

Table of Contents

Natural Gas Facilities

At December 31, 2011, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,000 miles of natural gas distribution mains,
- Approximately 1,020 miles of natural gas transmission mains,
- Approximately 290 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 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, 2011:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)

Combined Cycle	Beaver Falls	Beaver Falls, NY	Gas/Oil	80.6
	Combined Locks	Combined Locks, WI	Gas	45.5(2)
	Syracuse	Syracuse, NY	Gas/Oil	82.8
Total Combined Cycle				208.9
Steam	Westwood	Tremont, PA	Waste Coal	32.5
Reciprocating Engine	Winnebago	Rockford, IL	Landfill Gas	6.1
Solar	Various	Various States	Solar Irradiance	20.2(3)
Total Energy Assets				267.7
				Length of Pipeline (Miles)
Landfill Gas Transportation	LGS	Brazoria County, TX	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.

(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, 6.8 megawatts is Integrys Energy Services portion of total solar capacity based on their 50% ownership in INDU Solar Holdings, LLC.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS

For information on material legal proceedings and matters related to us and our subsidiaries, see Note 16, *Commitments and Contingencies*.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

Table of Contents

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:

	2011			2010		
Quarter	**High**	**Low**	**Dividends**	**High**	**Low**	**Dividends**
First	**$ 51.03**	**$ 47.51**	**$ 0.68**	$ 47.67	$ 40.53	$ 0.68
Second	**54.02**	**49.10**	**0.68**	50.92	42.81	0.68
Third	**52.79**	**42.76**	**0.68**	52.74	42.92	0.68
Fourth	**54.61**	**45.75**	**0.68**	54.45	46.73	0.68

As of the close of business on February 24, 2012, we had 29,465 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 subsidiaries to pay us dividends, see Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources* and Note 20, *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 year ended December 31, 2011:

			Issuer Purchases of Equity Securities	
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
01/01/11 - 01/31/11 (1)	9,788	$ 49.09		
02/01/11 - 02/28/11				
03/01/11 - 03/31/11				
04/01/11 - 04/30/11				
05/01/11 - 05/31/11 (1) (2)	126,838	53.61		
06/01/11 - 06/30/11 (1) (2) (3)	82,503	50.87		
07/01/11 - 07/31/11 (1) (2)	16,082	52.02		
08/01/11 - 08/31/11 (2)	20,799	47.62		
09/01/11 - 09/30/11 (2) (3)	76,823	50.60		
10/01/11 - 10/31/11 (1) (2)	23,009	50.16		
11/01/11 - 11/30/11 (1) (2)	21,666	51.36		
12/01/11 - 12/31/11 (1) (2) (3)	117,514	52.45		
Total	495,022	$ 51.76		

(1) Represents shares purchased in the open market by American Stock Transfer and Trust Company to satisfy obligations under various equity compensation plans.

(2) Represents shares purchased in the open market by American Stock Transfer and Trust Company to provide shares to participants in the Stock Investment Plan.

(3) Represents shares purchased in the open market by American Stock Transfer and Trust Company and held in a rabbi trust under our Deferred Compensation Plan.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

INTEGRYS ENERGY GROUP, INC.

COMPARATIVE FINANCIAL DATA AND

OTHER STATISTICS (2007 TO 2011)

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)	**2011**	**2010**	**2009**	**2008**	**2007 ***
Total revenues	**$ 4,708.7**	$ 5,203.2	$ 7,499.8	$ 14,047.8	$ 10,292.4
Net income (loss) from continuing operations	**230.9**	223.5	(70.3)	114.8	181.0
Net income (loss) attributed to common shareholders	**227.4**	220.9	(69.6)	116.5	251.3
Total assets	**9,983.2**	9,816.8	11,844.6	14,268.7	11,234.4
Preferred stock of subsidiary	**51.1**	51.1	51.1	51.1	51.1
Long-term debt (excluding current portion)	**1,872.0**	2,161.6	2,394.7	2,285.7	2,265.1
Average shares of common stock					
Basic	**78.6**	77.5	76.8	76.7	71.6
Diluted	**79.1**	78.0	76.8	77.0	71.8
Earnings (loss) per common share (basic)					
Net income (loss) from continuing operations	**$ 2.90**	$ 2.85	$ (0.95)	$ 1.46	$ 2.49
Earnings (loss) per common share (basic)	**2.89**	2.85	(0.91)	1.52	3.51
Earnings (loss) per common share (diluted)					
Net income (loss) from continuing operations	**2.88**	2.83	(0.95)	1.45	2.48
Earnings (loss) per common share (diluted)	**2.87**	2.83	(0.91)	1.51	3.50
Dividends per common share declared	**2.72**	2.72	2.72	2.68	2.56
Stock price at year-end	**$ 54.18**	$ 48.51	$ 41.99	$ 42.98	$ 51.69
Book value per share	**$ 38.01**	$ 37.57	$ 37.51	$ 40.66	$ 42.58
Return on average equity	**7.7%**	7.7%	(2.4)%	3.6%	8.5%
Number of common stock shareholders	**28,993**	30,352	32,755	34,016	35,212
Number of employees	**4,619**	4,612	5,025	5,191	5,231

* Includes the impact of the PELLC merger on February 21, 2007.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIALCONDITION 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. This is critical to our success as a strategically focused regulated business. We believe the following projects have helped, or will help, maintain and grow our regulated utility base and meet our customers needs:

- An accelerated annual investment in natural gas distribution facilities (primarily replacement of cast iron mains) at PGL.

- WPS s continued investment in environmental projects to improve air quality and meet the requirements set by environmental regulators. Capital projects to construct and/or upgrade equipment to meet or exceed required environmental standards are planned each year.

- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.0 billion of transmission assets at December 31, 2011. ATC plans to invest approximately $3.8 billion to $4.4 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.

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

Continuing Emphasis on 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. Ensuring continued reliability for our customers, we strive to effectively operate a mixed portfolio of generation assets and invest in new generation and natural gas distribution assets, while maintaining or exceeding environmental standards. This allows us to provide a safe, reliable, value-priced service to our customers. We concentrate our efforts on improving and operating efficiently in order to reduce costs and maintain a low risk profile. We actively evaluate opportunities for adding more renewable generation to provide additional environmentally sound energy to our portfolio. 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. In addition, Integrys Energy Services continues to develop, acquire, own and operate renewable energy projects, primarily distributed solar generation, in the United States. We have repositioned this subsidiary from a focus on significant growth in wholesale and retail electric markets across the United States and Canada, to a focus 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 customer based business. The current strategy is intended to result in more 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 are implemented to encourage top performance in the areas of project management, process improvement, contract administration, and compliance in order to reduce costs and manage projects and activities within appropriate budgets, schedules, and regulations.

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

Table of Contents

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 opportunities 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 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Natural gas utility operations	**$ 103.3**	$ 84.0	$ (172.1)	23.0%	N/A
Electric utility operations	**100.5**	109.8	88.9	(8.5)%	23.5%
Electric transmission investment	**47.8**	46.2	45.5	3.5%	1.5%
Integrys Energy Services operations	**(6.1)**	3.3	3.8	N/A	(13.2)%
Holding company and other operations	**(18.1)**	(22.4)	(35.7)	(19.2)%	(37.3)%
Net income (loss) attributed to common shareholders	**$ 227.4**	$ 220.9	$ (69.6)	2.9%	N/A
Basic earnings (loss) per share	**$ 2.89**	$ 2.85	$ (0.91)	1.4%	N/A
Diluted earnings (loss) per share	**$ 2.87**	$ 2.83	$ (0.91)	1.4%	N/A
Average shares of common stock					
Basic	**78.6**	77.5	76.8	1.4%	0.9%
Diluted	**79.1**	78.0	76.8	1.4%	1.6%

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:

- The $31.8 million after-tax decreases in impairment losses recorded on generation plants and losses on dispositions at Integrys Energy Services.

- An additional $20.3 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.

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

- A $14.4 million after-tax increase in Integrys Energy Services realized margins.

These increases were partially offset by:

- A $66.1 million after-tax decrease in Integrys Energy Services margins from non-cash 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.

2010 Compared with 2009

We recognized net income attributed to common shareholders of $220.9 million in 2010 compared with a net loss attributed to common shareholders of $69.6 million in 2009. The primary driver of the $290.5 million increase in earnings was an after-tax noncash goodwill impairment loss of $248.8 million recorded in 2009, compared with no goodwill impairment losses in 2010. Other factors contributing to the increase were the combined approximate $69 million after-tax positive impact on margins of electric and natural gas distribution rate increases effective in 2010, and a $22.5 million after-tax reduction in restructuring expenses year over year. These increases in earnings were partially offset by after-tax impairment charges of $25.9 million in 2010 related to three natural gas-fired generation plants at Integrys Energy Services.

Table of Contents

Regulated Natural Gas Utility Segment Operations

(Millions, except degree days)	Year Ended December 31 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,998.0**	$ 2,057.2	$ 2,237.5	(2.9)%	(8.1)%
Purchased natural gas costs	**1,101.4**	1,152.0	1,382.0	(4.4)%	(16.6)%
Margins	**896.6**	905.2	855.5	(1.0)%	5.8%
Operating and maintenance expense	**523.6**	542.1	532.6	(3.4)%	1.8%
Goodwill impairment loss			291.1	N/A	(100.0)%
Restructuring expense		(0.2)	6.9	(100.0)%	N/A
Depreciation and amortization expense	**126.1**	130.9	106.1	(3.7)%	23.4%
Taxes other than income taxes	**35.6**	34.4	33.4	3.5%	3.0%
Operating income (loss)	**211.3**	198.0	(114.6)	6.7%	N/A
Miscellaneous income	**2.2**	1.6	3.1	37.5%	(48.4)%
Interest expense	**(48.4)**	(49.7)	(52.2)	(2.6)%	(4.8)%
Other expense	**(46.2)**	(48.1)	(49.1)	(4.0)%	(2.0)%
Income (loss) before taxes	**$ 165.1**	$ 149.9	$ (163.7)	10.1%	N/A
Retail throughput in therms					
Residential	**1,541.5**	1,496.4	1,602.8	3.0%	(6.6)%
Commercial and industrial	**469.5**	455.5	501.4	3.1%	(9.2)%
Other	**61.3**	53.7	60.8	14.2%	(11.7)%
Total retail throughput in therms	**2,072.3**	2,005.6	2,165.0	3.3%	(7.4)%
Transport throughput in therms					
Residential	**237.4**	224.4	237.7	5.8%	(5.6)%
Commercial and industrial	**1,559.7**	1,504.0	1,403.9	3.7%	7.1%
Total transport throughput in therms	**1,797.1**	1,728.4	1,641.6	4.0%	5.3%
Total throughput in therms	**3,869.4**	3,734.0	3,806.6	3.6%	(1.9)%
Weather					
Average heating degree days	**6,675**	6,440	7,061	3.6%	(8.8)%

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 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. The decrease in margins was driven by the approximate $19 million negative year-over-year impact at PGL and NSG of higher regulatory refunds and lower regulatory recoveries that are offset by equal decreases in operating and maintenance expense, 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 26, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders and Note 16, *Commitment and Contingencies*, for more information on our manufactured gas plant sites.

Table of Contents

The decrease in margins was partially offset by:

- An approximate $4 million net increase in margins as a result of 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, as shown by the 3.6% increase in heating degree days, drove an approximate $6 million increase in margins.

- Partially offsetting these increases was an approximate $19 million decrease due to decoupling mechanisms at certain natural gas utilities. Although decoupling was implemented to minimize the impact of changes in sales volumes, it does not cover all jurisdictions or customers. During 2011, decoupling lessened the positive impact from some of the increased sales volumes through higher future customer refunds. During 2010, decoupling lessened the negative impact from some of the decreased sales volumes through higher future customer recoveries.

- An approximate $4 million net increase in margins from rate orders. See Note 26, *Regulatory Environment,* for more information on these rate orders.

- 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.

- The rate decrease 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 26, *Regulatory Environment,* for more information on this rider.

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, which is currently pending appeal before the Michigan Court of Appeals.

- 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 related to retirement of certain computer hardware.

Table of Contents

- 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.

2010 Compared with 2009

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 revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 9% decrease in the average per-unit cost of natural gas sold during 2010, which had no impact on margins.

Regulated natural gas utility segment margins increased $49.7 million, driven by the approximate $96 million positive impact of rate increases. These rate increases were necessary, in part, to recover higher operating expenses (as discussed below). See Note 26, *Regulatory Environment,* for more information on these rate increases. The rate increases at PGL and NSG had an approximate $77 million positive impact on margins. The rate increase at WPS and MGU had an approximate $13 million and $3 million positive impact on margins, respectively. A rate increase at MERC related to its CIP had an approximate $3 million positive impact on margins. CIP margins are offset by a corresponding increase in operating and maintenance expense and, therefore, had no impact on earnings.

This increase in margins was partially offset by:

• An approximate $28 million decrease in margins resulting from the 1.9% lower volumes sold, related to:

• An approximate $19 million decrease related to warmer weather during 2010, as evidenced by the 8.8% decrease in heating degree days.

• An approximate $19 million decrease related to lower sales volumes excluding the impact of weather. Residential customer sales volumes decreased, which we attribute to energy conservation, efficiency efforts, and general economic conditions. This decrease was partially offset by a net increase in commercial and industrial sales volumes for both retail and transportation customers, driven by certain transportation customers of MERC and MGU.

• Partially offsetting these decreases was the approximate $10 million increase in 2010 due to decoupling mechanisms in place at certain of our regulated natural gas utilities. Under decoupling, certain of our regulated natural gas utilities are allowed to defer the difference between the actual and rate case authorized delivery charge components of margin from certain customers and adjust future rates in accordance with rules applicable to each jurisdiction. The decoupling mechanism for WPS s natural gas utility includes an annual $8.0 million cap for the deferral of any excess or shortfall from the rate case authorized margin. This cap was reached in the first quarter of 2010 but was not reached in 2009.

• An approximate $18 million net decrease in margins driven by lower recovery of environmental cleanup expenditures at our former manufactured gas plant sites, partially offset by an increase in margins related to recoveries received under the PGL and NSG bad debt riders. These amounts were offset by an equal net decrease in operating and maintenance expense resulting from lower net amortization of the related regulatory assets and, therefore, had no impact on earnings. Recoveries under these riders represent net billings to customers of the excess or deficiency of actual 2008 and 2009 bad debt expense over bad debt expense reflected in utility rates during those same periods. See Note 26, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders.

Table of Contents

Operating Income (Loss)

Operating income at the regulated natural gas utility segment increased $312.6 million. This increase was primarily driven by the positive impact of a $291.1 million noncash goodwill impairment loss that was recorded in the first quarter of 2009. Also contributing to the increase was the $49.7 million increase in the natural gas margins discussed above, partially offset by a $28.2 million increase in other operating expenses. See Note 10, *Goodwill and Other Intangible Assets*, for information related to the goodwill impairment loss recorded in 2009.

The increase in other operating expenses primarily related to:

- A $24.8 million increase in depreciation and amortization expense, primarily due to the ICC s rate order for PGL and NSG, effective January 28, 2010. This rate order allows earlier recovery in rates for net dismantling costs by including them as a component of depreciation rates applied to natural gas distribution assets. The increase also reflects the impact of a $2.5 million write-off of certain MGU assets, which is currently pending appeal before the Michigan Court of Appeals.

- A $12.9 million increase in expenses related to energy conservation programs and enhanced efficiency initiatives. This increase includes expenses related to the CIP that were recovered through the MERC rate increase discussed in margins above.

- A $14.7 million increase in employee benefit costs, primarily driven by an increase in other postretirement benefit costs.

- A $7.4 million increase in asset usage charges from IBS related to implementation of both a work asset management system for natural gas operations and an upgrade to an enterprise resource planning system for finance and supply chain services.

- These increases were partially offset by:

- An approximate $18 million net decrease due to approximately $25 million of lower amortization of the regulatory asset related to environmental cleanup expenditures for manufactured gas plant sites, partially offset by approximately $7 million of amortization related to the regulatory assets recorded as a result of the PGL and NSG bad debt riders. This net decrease was passed through to customers in rates and, therefore, had no impact on earnings.

- A $7.1 million decrease in restructuring expenses related to a reduction in workforce. See Note 3, *Restructuring Expense,* for more information.

- A $6.1 million decrease in labor costs as a result of the reduction in workforce and company-wide furloughs implemented as a part of previously announced cost management efforts.

Table of Contents

Regulated Electric Utility Segment Operations

(Millions, except degree days)	2011	Year Ended December 31 2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,307.3**	$ 1,338.9	$ 1,301.6	(2.4)%	2.9%
Fuel and purchased power costs	**546.3**	563.9	584.5	(3.1)%	(3.5)%
Margins	**761.0**	775.0	717.1	(1.8)%	8.1%
Operating and maintenance expense	**421.5**	417.2	392.0	1.0%	6.4%
Restructuring expense	**0.2**	(0.3)	8.6	N/A	N/A
Depreciation and amortization expense	**88.5**	94.7	90.3	(6.5)%	4.9%
Taxes other than income taxes	**47.6**	45.6	46.6	4.4%	(2.1)%
Operating income	**203.2**	217.8	179.6	(6.7)%	21.3%
Miscellaneous income	**0.8**	1.5	4.8	(46.7)%	(68.8)%
Interest expense	**(41.8)**	(43.9)	(41.6)	(4.8)%	5.5%
Other expense	**(41.0)**	(42.4)	(36.8)	(3.3)%	15.2%
Income before taxes	**$ 162.2**	$ 175.4	$ 142.8	(7.5)%	22.8%
Sales in kilowatt-hours					
Residential	**3,135.6**	3,114.3	3,043.0	0.7%	2.3%
Commercial and industrial	**8,520.9**	8,439.6	8,155.5	1.0%	3.5%
Wholesale	**4,256.8**	4,994.7	5,079.1	(14.8)%	(1.7)%
Other	**38.4**	39.1	40.0	(1.8)%	(2.3)%
Total sales in kilowatt-hours	**15,951.7**	16,587.7	16,317.6	(3.8)%	1.7%
Weather WPS:					
Heating degree days	**7,524**	7,080	7,962	6.3%	(11.1)%
Cooling degree days	**603**	616	274	(2.1)%	124.8%
Weather UPPCO:					
Heating degree days	**8,676**	8,002	9,317	8.4%	(14.1)%
Cooling degree days	**305**	301	99	1.3%	204.0%

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 26, *Regulatory Environment*.

- An approximate $5 million decrease in margins from wholesale customers. The decrease was due to lower sales volumes and lower non-fuel 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.

Table of Contents

- 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.

2010 Compared with 2009

Margins

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric 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. 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 increased $57.9 million, driven by:

- An approximate $26 million increase in margins driven by lower fuel and purchased power costs incurred during 2010 as compared with authorized fuel and purchased power cost recovery rates.

- An approximate $21 million combined positive impact of retail electric rate increases at both WPS and UPPCO, effective January 1, 2010.

- An approximate $7 million increase in margins due to a 2.7% increase in sales volumes to residential customers at WPS, primarily related to warmer year-over-year weather during the cooling season, as evidenced by the increase in cooling degree days. Margins were impacted by the year-over-year increase in sales volumes because WPS reached the annual $14.0 million electric decoupling cap in the second quarter of 2010 and 2009 and remained over the cap through the end of both years. Therefore, no additional decoupling deferral was allowed for additional shortfalls from authorized margin for the remainder of both years. Under decoupling, WPS is allowed to defer (up to the established cap) the difference between its actual margin and the rate case authorized margin recognized from residential and small commercial and industrial customers.

Table of Contents

- An approximate $7 million increase in margins due to a 7.5% increase in sales volumes to large commercial and industrial customers at WPS, primarily related to changes in the business operations of these customers year over year.

- These increases in regulated electric utility segment margins were partially offset by an approximate $2 million decrease in margins from WPS s wholesale customers, primarily due to a decrease in sales volumes.

Operating Income

Operating income at the regulated electric utility segment increased $38.2 million, driven by the $57.9 million increase in margins, partially offset by a $19.7 million increase in operating expenses.

The increase in operating expenses was the result of:

- A $13.9 million increase in electric transmission expense.

- A $12.7 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 $7.5 million increase in employee benefit costs. The increase was partially due to an increase in pension and other postretirement benefit expenses, driven by the amortization of negative investment returns on plan assets from prior years.

- A $4.4 million increase in depreciation and amortization expense, primarily related to the Crane Creek Wind Farm being placed in service for accounting purposes in December 2009.

- These increases were partially offset by:

- An $8.9 million year-over-year decrease in restructuring expenses related to a reduction in workforce. See Note 3, *Restructuring Expense*, for more information.

- A $6.2 million decrease in labor costs, driven by the reduction in workforce and company-wide furloughs implemented as part of previously announced cost management efforts.

- A $2.1 million decrease in electric maintenance expense at WPS, primarily related to a greater number of planned outages at its generation plants during 2009 compared with 2010.

Other Expense

Other expense at the regulated electric utility segment increased $5.6 million, driven by a decrease in AFUDC, primarily related to the construction of the Crane Creek Wind Farm in 2009.

Electric Transmission Investment Segment Operations

2011 Compared with 2010

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $1.5 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. We earn higher returns each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits.

2010 Compared with 2009

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $2.3 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. We earn higher returns each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits.

Table of Contents

Integrys Energy Services Nonregulated Segment Operations

(Millions, except natural gas sales volumes)	Year Ended December 31 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,395.9**	$ 1,823.7	$ 3,994.0	(23.5)%	(54.3)%
Cost of sales	**1,272.7**	1,614.3	3,696.1	(21.2)%	(56.3)%
Margins	**123.2**	209.4	297.9	(41.2)%	(29.7)%
Margin Detail					
Realized retail electric margins	**98.5**	85.4(2)(4)	82.0(4)	15.3%	4.1%
Realized wholesale electric margins	**(0.2)**(1)	(8.2)(3)	40.3	(97.6)%	N/A
Realized energy asset margins	**31.1**	34.5	37.9	(9.9)%	(9.0)%
Fair value accounting adjustments	**(30.7)**	36.0	29.9	N/A	20.4%
Electric and other margins	**98.7**	147.7	190.1	(33.2)%	(22.3)%
Realized retail natural gas margins	**49.1**	50.0(4)	68.7(4)	(1.8)%	(27.2)%
Realized wholesale natural gas margins	**3.9**(1)	(3.3)	40.8	N/A	N/A
Lower-of-cost-or-market inventory adjustments	**(10.7)**	6.8	155.4	N/A	(95.6)%
Fair value accounting adjustments	**(17.8)**	8.2	(157.1)	N/A	N/A
Natural gas margins	**24.5**	61.7	107.8	(60.3)%	(42.8)%
Operating and maintenance expense	**108.8**	117.6	188.6	(7.5)%	(37.6)%
Impairment losses on property, plant, and equipment	**4.6**	43.2	0.7	(89.4)%	6,071.4%
Restructuring expense	**1.8**	8.3	27.2	(78.3)%	(69.5)%
Net (gain) loss on Integrys Energy Services dispositions related to strategy change	**(0.3)**	14.1	28.9	N/A	(51.2)%
Depreciation and amortization	**12.7**	17.2	19.0	(26.2)%	(9.5)%
Taxes other than income taxes	**7.0**	5.0	7.4	40.0%	(32.4)%
Operating income (loss)	**(11.4)**	4.0	26.1	N/A	(84.7)%
Miscellaneous income	**0.4**	9.1	6.0	(95.6)%	51.7%
Interest expense	**(2.3)**	(6.7)	(13.1)	(65.7)%	(48.9)%
Other income (expense)	**(1.9)**	2.4	(7.1)	N/A	N/A
Income (loss) before taxes	**$ (13.3)**	$ 6.4	$ 19.0	N/A	(66.3)%
Physically settled volumes					
Retail electric sales volumes in kwh	**12,416.5**	12,647.9(6)	15,045.3(6)	(1.8)%	(15.9)%
Wholesale electric sales volumes in kwh	**320.1**(5)	1,319.9	3,965.2	(75.7)%	(66.7)%
Retail natural gas sales volumes in bcf	**125.5**	133.3(6)	236.7(6)	(5.9)%	(43.7)%
Wholesale natural gas sales volumes in bcf		27.5	402.5	(100.0)%	(93.2)%

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 electric generation assets.

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

2011 Compared with 2010

Revenues

Revenues decreased $427.8 million, driven by lower sales volumes resulting from Integrys Energy Services strategy change, and lower year-over-year average commodity prices.

Table of Contents

Margins

Integrys Energy Services margins decreased $86.2 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 $66.7 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 $15.4 million, driven by the $86.2 million decrease in margins discussed above, partially offset by a $70.8 million decrease in operating expenses.

The decrease in operating expense was primarily related to:

- A $38.6 million decrease in impairment losses recorded on generation plants.
- A $14.4 million decrease due to losses on Integrys Energy Services dispositions in 2010 related to its strategy change.
- A $6.5 million decrease in restructuring expense.
- A $4.5 million decrease in depreciation and amortization expense, driven by lower book value of the generation plants for which impairment losses were recorded in 2010.

Table of Contents

- A $4.7 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.

Other Income (Expense)

Integrys Energy Services other income decreased $4.3 million. The main driver for the decrease was an $8.7 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 $4.4 million decrease in interest expense driven by reduced business size as a result of Integrys Energy Services strategy change.

2010 Compared with 2009

Revenues

Revenues decreased $2,170.3 million during 2010, compared with 2009, as a result of our decision to reduce the scale, scope, and risk attributes of Integrys Energy Services by focusing on selected retail electric and natural gas markets in the United States and investments in energy assets with renewable attributes. See Note 5, *Dispositions*, for a discussion of the dispositions completed in connection with Integrys Energy Services strategy change. Also contributing to the decrease in revenues were lower energy prices, as the average market price of natural gas and electricity decreased approximately 7% and 4% respectively, year over year.

Margins

Integrys Energy Services margins decreased $88.5 million during 2010, compared with 2009. 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 $3.4 million during 2010, compared with 2009, driven by:

- A $9.2 million increase in margins in the Illinois market, primarily driven by a change in pricing methodology and customer mix that was implemented as part of Integrys Energy Services strategy change.

- A $5.5 million increase in margins in the Michigan market. This increase was driven by higher sales volumes due to increased marketing efforts.

- The above increases in realized retail electric margins were partially offset by a $9.0 million decrease in margins related to the sale of the Texas retail electric business in June 2010, driven by reduced sales volumes and a $1.4 million decrease related to the settlement of supply contracts. See Note 5, *Dispositions*, for a discussion of this sale.

Realized wholesale electric margins

Realized wholesale electric margins decreased $48.5 million year over year, including negative margins of $9.3 million in 2010 related to the settlement of wholesale supply contracts in connection with Integrys Energy Services strategy change. Wholesale transactions and structured origination activity were significantly scaled back in conjunction with Integrys Energy Services sale of substantially all of its United States wholesale electric marketing and trading business, which was completed in February 2010. See Note 5, *Dispositions*, for more information on Integrys Energy Services sale of its United States wholesale electric marketing and trading business.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $6.1 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.

Table of Contents

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $18.7 million during 2010, compared with 2009, driven by:

- A $7.6 million decrease driven by reduced sales volumes due to the sale of Integrys Energy Services Canadian retail natural gas portfolio in September 2009. See Note 5, *Dispositions*, for a discussion of this sale.

- A $7.5 million decrease in margins in the Illinois market, primarily due to the negative year-over-year impact of the withdrawal of a significant amount of natural gas from storage in the first half of 2009, resulting in higher realized margins during that period. Also contributing to the decrease were lower sales volumes resulting from Integrys Energy Services strategy change.

Realized wholesale natural gas margins

Realized wholesale natural gas margins decreased $44.1 million year over year due to Integrys Energy Services completing the sale of substantially all of its wholesale natural gas business in December 2009. Additional components of the wholesale natural gas business were sold in March 2010 and May 2010. The remaining realized wholesale natural gas activity at Integrys Energy Services is related to residual contracts that will settle in the first half of 2011. The risks associated with these residual contracts are economically hedged. See Note 5, *Dispositions*, for more information on Integrys Energy Services sale of its wholesale natural gas business.

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 $148.6 million year-over-year decrease in margins from inventory adjustments was driven by a lower volume of inventory withdrawn from storage in 2010 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 $165.3 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.

Operating Income (Loss)

Integrys Energy Services operating income decreased $22.1 million year over year, driven by the $88.5 million decrease in margins discussed above, and a $43.2 million noncash impairment loss related to three natural gas-fired generation plants in the third quarter of 2010. These decreases were partially offset by a $71.0 million decrease in operating and maintenance expense, an $18.9 million decrease in restructuring expense, and a $14.8 million decrease in the net loss on Integrys Energy Services dispositions related to its strategy change (which primarily resulted from mark-to-market timing differences that have historically caused earnings volatility at Integrys Energy Services).

The decrease in operating and maintenance expense was driven by:

- A $46.0 million year-over-year decrease in employee payroll and benefit related expenses, primarily due to the reduction in workforce associated with Integrys Energy Services strategy change.

- A $10.5 million year-over-year decrease in bad debt expense driven by the partial recovery in 2010 of receivables fully reserved in prior years, and a decrease in reserves resulting from reduced business activity.

- The $9.0 million positive year-over-year impact of a fee incurred in the second quarter of 2009 related to an agreement with a counterparty that enabled Integrys Energy Services to reduce collateral support requirements.

- An $8.0 million year-over-year decrease in broker commissions, contractor expenses, and various other fees, resulting from reduced business activity associated with Integrys Energy Services strategy change.

- The above decreases in operating and maintenance expense were partially offset by $8.1 million of intercompany fees related to a credit agreement established in 2010 with the holding company.

Table of Contents

Other Income (Expense)

Integrys Energy Services other income increased $9.5 million year over year, driven by a $4.3 million gain reclassified from accumulated other comprehensive income in 2010 related to foreign currency translation adjustments recorded in prior periods, as well as a $6.4 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 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Operating income (loss)	**$ 5.7**	$ 8.3	$ (1.9)	(31.3)%	N/A
Other expense	**(34.0)**	(45.9)	(58.1)	(25.9)%	(21.0)%
Net loss before taxes	**$ (28.3)**	$ (37.6)	$ (60.0)	(24.7)%	(37.3)%

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.

2010 Compared with 2009

Operating Income (Loss)

Operating income at the holding company and other segment increased $10.2 million, driven by $8.1 million of intercompany fees charged by the holding company to Integrys Energy Services related to a credit agreement established in 2010.

Other Expense

Other expense at the holding company and other segment decreased $12.2 million, driven by a $14.6 million decrease in external interest expense.

Provision for Income Taxes

	Year Ended December 31		
	2011	**2010**	**2009**
Effective Tax Rate	**36.7%**	39.9%	624.6%

2011 Compared with 2010

Our effective tax rate decreased during 2011. In the fourth quarter of 2011, we reduced the provision for income taxes by $5.8 million when we recorded a regulatory asset related to deferred income taxes previously expensed as part of the 2010 federal health care reform. We were authorized recovery of these income taxes through our recently approved rate order for PGL and NSG. As discussed below, we expensed $10.8 million of deferred income taxes as a result of the federal health care reform in 2010. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform* for more information. The decrease in the effective tax rate during 2011 was partially offset when we increased our provision for income taxes and deferred income tax liabilities by $6.0 million for tax law changes in Michigan and Wisconsin. See *Liquidity and Capital Resources, Other Future Considerations Recent Tax Law Changes* for more information.

Table of Contents

For information on changes in the deferred income tax balances, see Note 15, Income Taxes.

2010 Compared with 2009

Our effective tax rate decreased during 2010. The rate decreased primarily because a significant portion of our $291.1 million noncash pre-tax goodwill impairment loss recorded in 2009 was not deductible for tax purposes. Partially offsetting this decrease in the effective tax rate was 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. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform* for more information. As a result, we expensed $10.8 million of deferred income taxes during 2010. This amount excluded $1.0 million for which UPPCO was authorized recovery from ratepayers.

Discontinued Operations, Net of Tax

2011 Compared with 2010

Income from discontinued operations, net of tax, decreased $0.6 million in 2011. During 2011, we remeasured an unrecognized tax benefit liability related to the 2007 sale of Peoples Energy Production Company, including an adjustment for a lapse in the statute of limitations for certain states associated with these tax filings.

2010 Compared with 2009

Income from discontinued operations, net of tax, decreased $2.6 million in 2010. During 2009, Integrys Energy Services recognized a $3.9 million ($2.4 million after tax) gain on the sale of its energy management consulting business in discontinued operations. During 2010, Integrys Energy Services recorded a $0.2 million after-tax gain in discontinued operations when contingent payments were earned related to the sale of this business.

For more information on the discontinued operations discussed above, see Note 5, *Dispositions,* and Note 27, *Segments of Business*.

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

2011 Compared with 2010

Net cash provided by operating activities was $721.9 million during 2011, compared with $725.2 million during 2010. The $3.3 million decrease in net cash provided by operating activities was mainly driven by:

- Net cash used for working capital of $34.2 million in 2011, compared with $40.8 million of net cash provided by working capital in 2010. The $75.0 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 $28.0 million in 2011, compared to a decrease of $51.1 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 $46.2 million decrease in other current assets in 2011, compared with an $85.5 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 $68.4 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.

Table of Contents

- The net increase in working capital requirements was partially offset by a $70.3 million net decrease in contributions to pension and other postretirement benefit plans.

2010 Compared with 2009

Net cash provided by operating activities was $725.2 million during 2010, compared with $1,606.3 million during 2009. The $881.1 million decrease in net cash provided by operating activities was mainly driven by:

- A $746.5 million net decrease in cash provided by working capital, driven by:

- A $767.2 million year-over-year decrease in cash generated from customer collections, primarily due to the Integrys Energy Services strategy change, as well as lower year-over-year natural gas prices, which impacted both the regulated natural gas segment and Integrys Energy Services.

- A $393.0 million year-over-year decrease in cash generated from reduced inventory levels, mainly the result of the withdrawal of a significant amount of natural gas from storage at Integrys Energy Services during 2009 in order to improve its liquidity position.

- Partially offsetting these changes was a $578.9 million year-over-year decrease in cash used to pay accounts payable balances, driven by smaller accounts payable balances at Integrys Energy Services as a result of the strategy change, as well as lower year-over-year natural gas prices.

- Also offsetting these changes was a year-over-year increase in cash flows of $118.1 million due to a decrease in cash collateral provided to counterparties, due primarily to the change in Integrys Energy Services   business related to its strategy change.

- A $175.8 million year-over-year increase in deferred income taxes and investment tax credits, primarily driven by a change in tax accounting related to capitalization of overhead costs and legislation providing for bonus depreciation during 2010.

- A $148.5 million year-over-year increase in contributions to pension and other postretirement benefit plans.

Investing Cash Flows

2011 Compared with 2010

Net cash used for investing activities was $394.8 million during 2011, compared with $199.7 million during 2010. The $195.1 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 $52.6 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.

2010 Compared with 2009

Net cash used for investing activities was $199.7 million during 2010, compared with $440.7 million during 2009. The $241.0 million decrease in net cash used for investing activities was primarily driven by:

- A $185.4 million decrease in cash used to fund capital expenditures (discussed below).

- A $27.2 million year-over-year decrease in capital contributions to equity method investments, mainly related to ATC capital contributions.

- A year-over-year increase in proceeds received from the sale or disposal of assets, primarily related to Integrys Energy Services strategy change. For more information on these dispositions, see Note 5, *Dispositions*.

Table of Contents

Capital Expenditures

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

Reportable Segment (millions)	**2011**	**2010**	**2009**
Electric utility	**$ 84.1**	$ 87.2	$ 250.4
Natural gas utility	**199.3**	133.6	136.9
Integrys Energy Services	**18.0**	15.2	22.4
Holding company and other	**10.0**	22.8	34.5
Integrys Energy Group consolidated	**$ 311.4**	$ 258.8	$ 444.2

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.

The decrease in capital expenditures at the electric utility segment in 2010 compared with 2009 was primarily due to decreased expenditures related to the Crane Creek Wind Farm project, which was placed in service for accounting purposes in December 2009. The decrease in capital expenditures at the holding company and other segment was mainly due to lower expenditures in 2010 related to software projects.

Financing Cash Flows

2011 Compared with 2010

Net cash used for financing activities was $478.4 million during 2011, compared with $391.4 million during 2010. The $87.0 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 $28.3 million decrease in cash provided by the issuance of common stock. See *Significant Financing Activities* for more information.
- 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.

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.

2010 Compared with 2009

Net cash used for financing activities was $391.4 million during 2010, compared with $1,378.4 million during 2009. The $987.0 million year-over-year decrease in net cash used for financing activities was primarily driven by:

- A $761.5 million year-over-year decrease in the net repayment of short-term borrowings.
- A $298.6 million decrease due to net natural gas loan proceeds at Integrys Energy Services of $15.4 million during 2010, compared with the net repayment of $283.2 million of natural gas loans during 2009.

Table of Contents

- Partially offsetting these changes were $157.8 million of payments made during 2010 to buyers of the wholesale natural gas and electric businesses and payments for settlement of out-of-the-money transactions that were executed at the time of sale, compared with $33.9 million of proceeds received upon the sale of substantially all of the wholesale natural gas business during 2009. The out-of-the-money transactions were replacement supply trades for the retained retail operations and were transacted at the original transfer price between Integrys Energy Services wholesale and retail businesses. Payments made to the buyers to settle the replacement supply contracts were funded with proceeds received from the settlement of the related retail electric and retail natural gas sales contracts.

Significant Financing Activities

Our quarterly common stock dividend of $0.68 per share in 2011 remained the same as in 2010.

From January 1, 2010 through February 10, 2010, shares were purchased on the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of these plans. Beginning May 1, 2011, shares were again purchased on the open market to meet the requirements of these plans.

We had $303.3 million in outstanding commercial paper borrowings at December 31, 2011, and none outstanding at December 31, 2010. We had no short-term notes payable outstanding at December 31, 2011, and $10.0 million outstanding at December 31, 2010. We had no borrowings under revolving credit facilities at December 31, 2011, and 2010. See Note 12, *Short-Term Debt and Lines of Credit,* for more information.

For information on the issuance and redemption of our long-term debt and that of our subsidiaries, see Note 13, *Long-Term Debt*.

We use internally generated funds, commercial paper borrowings, and other short-term borrowings to satisfy most of our capital requirements. We also periodically issue long-term debt and common stock to reduce short-term debt, maintain desired capitalization ratios, and fund future growth.

We have our own commercial paper borrowing programs, as do WPS and PGL.

WPS periodically issues long-term debt to reduce short-term debt, fund future growth, and maintain capitalization ratios as authorized by the PSCW.

PGL and NSG periodically issue long-term debt in order to reduce short-term debt, refinance maturing securities, maintain desired capitalization ratios, and fund future growth. The specific forms of long-term financing, amounts, and timing depend on business needs, market conditions, and other factors.

Table of Contents

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 January 24, 2012, Standard & Poor s raised the issuer credit ratings for us, PGL, and NSG to A- from BBB+. In addition, they raised our senior unsecured debt rating to BBB+ from BBB and raised our junior subordinated notes rating to BBB from BBB-. The outlook for us, PGL, and NSG was revised to stable from positive. According to Standard & Poor s, the revised ratings reflect their view that our business risk profile improved to excellent from strong and that we continue to have a significant financial risk profile. The revised business risk profile assessment reflects the successful implementation of our strategic initiative to reduce our exposure to the nonutility businesses and our effective management of regulatory risk. WPS s outlook remained stable.

On May 27, 2010, Moody s revised the outlook for us and all of our subsidiaries to stable from negative. According to Moody s, the revised outlook reflected a reduced business risk profile driven by the recently completed restructuring of Integrys Energy Services into a smaller segment with significantly reduced collateral requirements. Moody s also raised the following ratings of our subsidiaries:

- The senior secured debt rating and first mortgage bonds rating of WPS were raised from A1 to Aa3.
- The senior secured debt ratings of PGL and NSG were raised from A2 to A1.

According to Moody s, the upgrade follows the August 2009 upgrade of the senior secured ratings of the majority of its investment grade regulated utilities (issuers with negative outlooks were excluded from the August 2009 upgrade).

Table of Contents

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2011, including those of our subsidiaries.

(Millions)	Total Amounts Committed	2012	Payments Due By Period 2013 to 2014	2015 to 2016	2017 and Thereafter
Long-term debt principal and interest payments (1)	$ 2,975.2	$ 358.1	$ 581.0	$ 633.9	$ 1,402.2
Operating lease obligations	81.6	8.5	13.8	8.1	51.2
Commodity purchase obligations (2)	2,669.0	700.5	707.7	345.6	915.2
Capital contributions to equity method investment	3.4	3.4			
Purchase orders (3)	418.2	416.8	1.4		
Pension and other postretirement funding obligations (4)	820.6	289.5	201.1	60.0	270.0
Total contractual cash obligations	$ 6,968.0	$ 1,776.8	$ 1,505.0	$ 1,047.6	$ 2,638.6

(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 commodity purchase obligations are generally entered into to meet obligations to deliver energy and related products to customers. The utility subsidiaries expect to recover the costs of their contracts in future customer rates.

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2014.

The table above does not reflect payments related to the manufactured gas plant remediation liability of $613.7 million at December 31, 2011, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 16, *Commitments and Contingencies*, for more information about environmental liabilities. The table also does not reflect payments for the December 31, 2011, liability of $22.4 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 15, *Income Taxes*, for more information on unrecognized tax benefits.

Table of Contents

Capital Requirements

As of December 31, 2011, our subsidiaries capital expenditures for the three-year period 2012 through 2014 were expected to be as follows:

(Millions)		
WPS		
Environmental projects	$	**510.7**
Electric and natural gas distribution projects		**201.1**
Electric and natural gas delivery and customer service projects		**63.7**
Other projects		**176.0**
UPPCO		
Repairs and safety measures at hydroelectric facilities		**16.6**
Other projects		**31.7**
MGU		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**34.8**
MERC		
Natural gas pipe distribution system and other projects		**53.2**
PGL		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**699.9**
NSG		
Natural gas pipe distribution system and other projects		**85.2**
Integrys Energy Services		
Solar and other projects		**98.6**
IBS		
Corporate services infrastructure projects		**96.2**
ITF		
Compressed natural gas fueling stations		**71.0**
Total capital expenditures	$	**2,138.7**

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

We expect to provide capital contributions to ATC (not included in the above table) of approximately $15 million from 2012 through 2014.

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

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 2012 through 2014 primarily through internally generated funds (net of forecasted dividend payments) and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth. We believe we have adequate financial flexibility and resources to meet our future needs.

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

Under an existing shelf registration statement, WPS may issue up to $500.0 million of senior debt securities with amounts, prices, and terms to be determined at the time of future offerings.

Table of Contents

At December 31, 2011, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 12, *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 13, *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 20, *Common Equity,* for more information on dividend restrictions.

Other Future Considerations

Decoupling

In certain jurisdictions, decoupling mechanisms have been implemented. These mechanisms differ state by state and allow utilities to adjust future rates to recover or refund all or a portion of the differences between actual and authorized margin.

- Decoupling for residential and small commercial and industrial sales was approved by the ICC on a four-year trial basis for PGL and NSG, effective March 1, 2008. Interveners, including the Illinois Attorney General, oppose decoupling and have appealed the ICC s approval. PGL and NSG actively support the ICC s decision to approve decoupling. In the PGL and NSG rate order approved on January 10, 2012, the ICC made the decoupling mechanism (based on total margin) permanent for both companies. The appeal of the original decoupling order is pending and, depending on the outcome, could impact the current rate order provision for decoupling.

- Decoupling for natural gas and electric residential and small commercial and industrial sales was approved by the PSCW on a four-year trial basis for WPS, effective January 1, 2009, and ending on December 31, 2012. 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. This decoupling mechanism includes an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are subject to these caps and are included in rates upon approval in a rate order. WPS expects to address decoupling beyond 2012 in its rate case filing for 2013.

- Decoupling for UPPCO was approved for the majority of customer classes by the MPSC, effective January 1, 2010, and ended on December 31, 2011. A new weather-normalized decoupling mechanism based on total margin will become effective for UPPCO on January 1, 2013. UPPCO has no decoupling mechanism in place for 2012.

- The MPSC granted an order, effective January 1, 2010, approving a decoupling mechanism for MGU that covers residential and small commercial and industrial customers. The decoupling mechanism does not adjust for weather-related usage, nor does it adjust for variations in volumes resulting from changes in customer count compared to rate case levels. The decoupling mechanism does not cover all customer classes.

- In Minnesota, MERC proposed a decoupling mechanism in its November 30, 2010 general rate case filing. A final order is expected in the second quarter of 2012.

See Note 26, *Regulatory Environment*, for more information.

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 December 2010, the EPA announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. The EPA planned to propose these standards in 2011 and finalize them in 2012; however, the proposal has since been delayed.

Table of Contents

A risk exists that any greenhouse gas legislation or regulation will increase the cost of producing energy using fossil fuels. However, we believe the capital expenditures being made at our plants are appropriate under any reasonable mandatory greenhouse gas program. We also believe that future expenditures by our regulated electric and natural gas utilities 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 posed by climate change for these areas are not expected to be significant at this time. Ongoing evaluations will be conducted as more information on the extent of such physical changes becomes available.

Property Tax Assessment on Natural Gas

Our subsidiaries and natural gas retailers purchase storage services from pipeline companies on interstate systems. Some states tax natural gas held as working natural gas in facilities located within their jurisdiction as personal property. Shippers that are being assessed a tax are actively protesting these property tax assessments. MERC is currently pursuing a protest through litigation in Kansas.

Federal Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (HCR) were signed into law. HCR contains various provisions that will affect the cost of providing health care coverage to our active and retired employees and their dependents. Although these provisions become effective at various times over the next 10 years, some provisions that affect the cost of providing benefits to retirees were reflected in our financial statements in 2010 and 2011.

Beginning in 2013, a provision of HCR will eliminate the tax deduction for employer-paid postretirement prescription drug charges to the extent those charges will be offset by the receipt of a federal Medicare Part D subsidy. As a result, we eliminated $11.8 million of our deferred tax asset related to postretirement benefits in 2010. Of this amount, $10.8 million flowed through to net income as a component of income tax expense in 2010. The remaining $1.0 million was deferred for regulatory recovery at UPPCO. An additional $1.5 million was expensed in June 2011 for deferred income taxes related to a Wisconsin tax law change (see discussion in Recent Tax Law Changes below). In the fourth quarter of 2011, PGL and NSG recorded a regulatory asset of $5.8 million, reversing amounts previously expensed in 2010, as PGL and NSG were authorized recovery of these amounts in the rate order approved on January 10, 2012. In addition, WPS was authorized recovery in February 2012 for the portion related to its Michigan operations that was previously expensed in 2010. We expect to seek rate recovery for the remaining $5.9 million of income tax expense that relates to this tax law change associated with our regulated operations. If recovery in rates becomes probable in the remaining jurisdiction, income tax expense will be reduced in that period. We are not currently able to predict how much of the remaining portion, if any, will be recovered in rates.

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

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

The Dodd-Frank Act was signed into law in July 2010. However, significant rulings essential to its framework still remain outstanding. Depending on the final rules, certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. Final rules for these provisions are expected in the second quarter of 2012. We are monitoring developments related to this act and their impacts on our future financial results.

Recent Tax Law Changes

Federal

In December 2010, President Obama signed into law The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This act includes tax incentives, such as an extension and increase of bonus depreciation, the extension of the research and experimentation credit, and the extension of treasury grants in lieu of claiming the investment tax credit or production tax credit for certain renewable energy investments. In September 2010, President Obama signed into law the Small Business Jobs Act of 2010. This act includes tax incentives, such as an extension to bonus depreciation and changes to listed property, that affect us. We anticipate that these tax law changes will likely result in $140.0 million to $240.0 million of reduced cash payments for taxes during 2012. These tax incentives may also reduce utility rate base and,

Table of Contents

thus, future earnings relative to prior expectations. We have primarily used the proceeds from these incentives to make incremental contributions to our various employee benefit plans. In addition, these tax incentives have helped reduce our financing needs.

In December 2011, the National Defense Authorization Act (NDAA) was enacted. The most significant 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 the investment tax credit or production tax credits. Prior to the enactment of NDAA, a regulated utility would have been required to amortize the grant in rates over the regulatory life of the renewable energy generating plant. Further, the allowed rate of return on the generating plant could not be reduced by the unamortized grant balance during the life of the plant. As a result of the enactment of NDAA, we are evaluating our options for taking advantage of cash grants in lieu of the production tax credits we are currently claiming for WPS s Crane Creek wind project.

Illinois

In January 2011, Governor Quinn signed into law the Taxpayer Accountability and Budget Stabilization Act. This act increased the corporate combined income tax rate from 7.3% to 9.5% retroactive to January 1, 2011. The rate decreases to 7.75% after 2014 and returns to 7.3% after 2024. We adjusted deferred taxes to reflect the changes in the tax rate in the first quarter of 2011. Due to the effects of regulation, and the timing of the January 10, 2012 rate order for PGL and NSG, we do not expect a material impact on income from this legislation.

Michigan

In May 2011, Governor Snyder signed legislation that replaced Michigan s business tax with a state income tax, effective January 1, 2012. In accounting for this tax law change, we expensed $4.4 million of deferred income taxes in 2011 primarily related to our nonregulated operations and our unitary filings. We deferred an additional $4.2 million in 2011 for recovery in future rates.

Wisconsin

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

OFF BALANCE SHEET ARRANGEMENTS

See Note 17, *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.

At December 31, 2011, those derivatives not designated as hedges were primarily commodity contracts used to manage price risk associated with natural gas and electricity purchase and sale activities. Cash flow hedge accounting treatment may be used to protect against changes in interest rates. Fair value hedge accounting may be used when we hold assets, liabilities, or firm commitments and enter into transactions that hedge the risk of changes in commodity prices or interest rates. To the extent that the hedging instrument is fully effective in offsetting the transaction being hedged, there is no impact on net income attributed to common shareholders prior to settlement of the hedge.

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. Of the total risk management assets on our balance sheets, \$14.9 million (5.1%) were classified as Level 3 measurements. Of the total risk management liabilities, \$22.8 million (5.5%) 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

Table of Contents

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, our own credit risk, and liquidity risk. The liquidity component of the fair value determination may be especially subjective when limited liquid market information is available. Changes in the underlying assumptions for the credit and liquidity risk components of fair value at December 31, 2011, would have had the following effects:

Change in Risk Components	Effect on Fair Value of Net Risk Management Liabilities at December 31, 2011 (Millions)	
100% increase	$	**5.0 decrease**
50% decrease	$	**2.5 increase**

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

As of July 1, 2011, Integrys Energy Services discontinued the use of cash flow hedge accounting. See Note 2, *Risk Management Activities* for further discussion.

Goodwill Impairment

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

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

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

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

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

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

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

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

Table of Contents

---

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

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 or contracted rates. Significant changes in these judgments and assumptions could have a material impact on our results of operations. At December 31, 2011 and 2010, our unbilled revenues were $282.1 million and $339.1 million, respectively. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns, commodity prices, and customer mix.

Pension and Other Postretirement Benefits

The costs of providing non-contributory defined benefit pension benefits and other postretirement benefits, described in Note 18, *Employee Benefit Plans*, are dependent upon 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.

Our 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 at the regulated 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 2011 Pension Cost**
Discount rate	(0.5)	$ 102.0	$ 8.9
Discount rate	0.5	(93.7)	(8.5)
Rate of return on plan assets	(0.5)	N/A	6.1
Rate of return on plan assets	0.5	N/A	(6.1)

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 2011 Postretirement Benefit Cost
Discount rate	(0.5)	$ 37.3	$ 2.7
Discount rate	0.5	(34.9)	(2.2)
Health care cost trend rate	(1.0)	(60.9)	(8.4)
Health care cost trend rate	1.0	73.7	10.9
Rate of return on plan assets	(0.5)	N/A	1.3
Rate of return on plan assets	0.5	N/A	(1.3)

The discount rates are selected based on hypothetical bond portfolios consisting of non-callable (or callable with make-whole provisions), non-collateralized, 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 2011, and 8.50% in 2010 and 2009. For 2011, 2010, and 2009, the actual rates of return on pension plan assets, net of fees, were 1.5%, 13.0%, and 22.0%, respectively.

Table of Contents

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 18, *Employee Benefit Plans*.

Regulatory Accounting

Our electric and natural gas 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. 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 electric and natural gas utility segments, and the status of any pending or potential deregulation legislation. 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.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our electric and natural gas 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, 2011, would result in a 17.9% decrease in total assets and a 5.7% decrease in total liabilities. The two largest regulatory assets at December 31, 2011, 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, 2011, would result in a 7.3% decrease in total assets. A write-off of the regulatory asset related to environmental remediation costs at December 31, 2011, would result in a 6.3% decrease in total assets. See Note 8, *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), *Summary of Significant Accounting Policies – Income Taxes*, and Note 15, *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.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks and Other Significant Risks

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 may use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

Utilities

The electric utilities purchase coal, natural gas, and fuel oil for use in power generation. They also buy power from the MISO market at a price that is often reflective of the underlying cost of natural gas used in power generation. 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. The costs of natural gas used by the natural gas utilities are also generally 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 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 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. Integrys Energy Services 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 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. The capped downside nature of the risks and duration of these positions would result in a VaR that would not be representative of the actual exposure. Therefore, Integrys Energy Services evaluates the exposures for these types of contracts by assessing the maximum potential loss of the positions, which is either the cost of the physical asset or the fixed demand charges for the contract.

VaR is a probabilistic approach to quantifying the exposure to market risk. 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. In addition to VaR, Integrys Energy Services employs other risk measurements including mark-to-market valuations, stress testing, and scenario-based testing. In conjunction with the VaR analysis, these other risk measurements provide the risk management analysis for Integrys Energy Services risk exposure.

VaR is not necessarily indicative of actual results that may occur. VaR has a number of limitations that are important to consider when evaluating the calculation results. Most importantly, VaR does not represent the maximum potential loss of the portfolio. Price movements outside of the relevant confidence levels can and do occur and may result in losses exceeding the reported VaR. Large short-term price moves can be caused by catastrophic weather events or other drivers of short-term supply and demand disruptions. Also, the holding period may not always be an adequate assessment of the timeframe to close out positions. Short-term reductions in market liquidity could cause Integrys Energy Services to hold positions open longer than anticipated, resulting in greater than predicted losses. Additionally, there are other risks not captured by the VaR metric including, but not limited to, the risk of customer and vendor nonperformance and the risks associated with the liquidity in the markets in which Integrys Energy Services transacts. Customer and vendor nonperformance risk could result in bad debt losses, realized and unrealized losses on commodity contracts, or increased supply costs in the event that contractual obligations of counterparties are not met. Market liquidity risk refers to the risk that Integrys Energy Services will not be able to efficiently enter or exit commodity positions.

Table of Contents

Integrys Energy Services VaR is calculated using non-discounted positions with a delta-normal approximation based on a one-day holding period and a 95% confidence level, as well as a ten-day holding period and a 99% confidence level. The delta-normal approximation is based on the assumption that changes in the value of the portfolio over short time periods, such as one day or ten days, are normally distributed. Integrys Energy Services 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, but excludes the positions mentioned above.

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)	2011	2010
As of December 31	**$ 0.2**	$ 0.2
Average for 12 months ended December 31	**0.2**	0.3
High for 12 months ended December 31	**0.3**	0.3
Low for 12 months ended December 31	**0.1**	0.2

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)	2011	2010
As of December 31	**$ 0.7**	$ 1.1
Average for 12 months ended December 31	**0.7**	1.4
High for 12 months ended December 31	**1.2**	1.5
Low for 12 months ended December 31	**0.5**	1.1

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

The year-over-year decrease in VaR was driven primarily by reduced business size, as a result of Integrys Energy Services strategy change.

Interest Rate Risk

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

Due to short-term borrowings, we are exposed to variable interest rates. Based on our variable rate debt outstanding at December 31, 2011, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.3 million. Comparatively, based on the variable rate debt outstanding at December 31, 2010, an increase in interest rates of 100 basis points would have increased annual interest expense by $1.4 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.

Table of Contents

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, 2011. 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, 2011, 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.

Table of Contents

B. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders 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, 2011, 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, 2011, 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, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin

February 28, 2012

Table of Contents

C. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 **(Millions, except per share data)**		**2011**		**2010**		**2009**
Utility revenues	**$**	**3,294.5**	$	3,368.5	$	3,495.8
Nonregulated revenues		**1,414.2**		1,834.7		4,004.0
Total revenues		**4,708.7**		5,203.2		7,499.8
Utility cost of fuel, natural gas, and purchased power		**1,635.3**		1,685.5		1,919.8
Nonregulated cost of sales		**1,281.6**		1,619.8		3,701.3
Operating and maintenance expense		**1,028.2**		1,045.6		1,098.4
Impairment losses on property, plant, and equipment		**4.6**		43.2		0.7
Restructuring expense		**2.0**		7.9		43.5
Net (gain) loss on Integrys Energy Services dispositions related to strategy change		**(0.3)**		14.1		28.9
Goodwill impairment loss						291.1
Depreciation and amortization expense		**250.1**		265.8		230.6
Taxes other than income taxes		**98.4**		93.2		96.3
Operating income		**408.8**		428.1		89.2
Miscellaneous income		**84.8**		91.5		89.0
Interest expense		**(128.8)**		(147.9)		(164.8)
Other expense		**(44.0)**		(56.4)		(75.8)
Income before taxes		**364.8**		371.7		13.4
Provision for income taxes		**133.9**		148.2		83.7
Net income (loss) from continuing operations		**230.9**		223.5		(70.3)
Discontinued operations, net of tax		**(0.4)**		0.2		2.8
Net income (loss)		**230.5**		223.7		(67.5)
Preferred stock dividends of subsidiary		**(3.1)**		(3.1)		(3.1)
Noncontrolling interest in subsidiaries				0.3		1.0
Net income (loss) attributed to common shareholders	**$**	**227.4**	$	220.9	$	(69.6)
Average shares of common stock						
Basic		**78.6**		77.5		76.8
Diluted		**79.1**		78.0		76.8
Earnings (loss) per common share (basic)						
Net income (loss) from continuing operations	**$**	**2.90**	$	2.85	$	(0.95)
Discontinued operations, net of tax		**(0.01)**				0.04
Earnings (loss) per common share (basic)	**$**	**2.89**	$	2.85	$	(0.91)
Earnings (loss) per common share (diluted)						
Net income (loss) from continuing operations	**$**	**2.88**	$	2.83	$	(0.95)
Discontinued operations, net of tax		**(0.01)**				0.04
Earnings (loss) per common share (diluted)	**$**	**2.87**	$	2.83	$	(0.91)
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.

Table of Contents

D. CONSOLIDATED BALANCE SHEETS

At December 31 (Millions)	2011	2010
Assets		
Cash and cash equivalents	**$ 28.1**	$ 179.0
Collateral on deposit	**50.9**	33.3
Accounts receivable and accrued unbilled revenues, net of reserves of $47.1 and $41.9, respectively	**737.7**	832.1
Inventories	**252.3**	247.9
Assets from risk management activities	**227.2**	236.9
Regulatory assets	**125.1**	117.9
Deferred income taxes	**94.2**	67.7
Prepaid taxes	**209.6**	269.9
Other current assets	**78.2**	65.7
Current assets	**1,803.3**	2,050.4
Property, plant, and equipment, net of accumulated depreciation of $3,018.7 and $2,900.2, respectively	**5,199.1**	5,013.4
Regulatory assets	**1,658.5**	1,495.1
Assets from risk management activities	**64.4**	89.4
Goodwill	**658.4**	642.5
Other long-term assets	**599.5**	526.0
Total assets	**$ 9,983.2**	$ 9,816.8
Liabilities and Equity		
Short-term debt	**$ 303.3**	$ 10.0
Current portion of long-term debt	**250.0**	476.9
Accounts payable	**426.6**	453.0
Liabilities from risk management activities	**311.6**	289.6
Accrued taxes	**70.5**	90.2
Regulatory liabilities	**67.5**	75.7
Other current liabilities	**217.2**	262.4
Current liabilities	**1,646.7**	1,657.8
Long-term debt	**1,872.0**	2,161.6
Deferred income taxes	**1,070.7**	860.5
Deferred investment tax credits	**44.0**	45.2
Regulatory liabilities	**332.5**	316.2
Environmental remediation liabilities	**615.1**	643.9
Pension and other postretirement benefit obligations	**749.3**	603.4
Liabilities from risk management activities	**102.0**	99.7
Asset retirement obligations	**397.2**	320.9
Other long-term liabilities	**141.1**	150.6
Long-term liabilities	**5,323.9**	5,202.0
Commitments and contingencies		
Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,904,935 shares outstanding	**78.3**	77.8
Additional paid-in capital	**2,579.1**	2,540.4
Retained earnings	**363.6**	350.8
Accumulated other comprehensive loss	**(42.5)**	(44.7)

Shares in deferred compensation trust		**(17.1)**		(18.5)
Total common shareholders equity		**2,961.4**		2,905.8
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		**51.1**		51.1
Noncontrolling interest in subsidiaries		**0.1**		0.1
Total liabilities and equity	**$**	**9,983.2**	$	9,816.8

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

Table of Contents

E. CONSOLIDATED STATEMENTS OF EQUITY

	Integrys Energy Group Common Shareholders Equity								
(Millions)	Deferred Compensation Trust and Treasury Stock	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders Equity	Preferred Stock of Subsidiary	Noncontrolling Interest	Total Equity
Balance at December 31, 2008	$ (16.5)	$ 76.4	$ 2,487.9	$ 614.7	$ (72.8)	$ 3,089.7	$ 51.1	$	$ 3,140.8
Net loss attributed to common shareholders				(69.6)		(69.6)		(1.0)	(70.6)
Other comprehensive income (loss)									
Cash flow hedges (net of tax of $17.0)					31.5	31.5			31.5
Unrecognized pension and other postretirement costs (net of tax of $3.2)					(6.7)	(6.7)			(6.7)
Available-for-sale securities (net of tax of $0.1)					(0.1)	(0.1)			(0.1)
Foreign currency translation (net of tax of $2.6)					4.1	4.1			4.1
Comprehensive loss						(40.8)			(41.8)
Purchase of deferred compensation shares	(3.1)					(3.1)			(3.1)
Stock based compensation	0.1		11.3			11.4			11.4
Dividends on common stock				(206.9)		(206.9)			(206.9)
Net contributions from noncontrolling parties								0.1	0.1
Other	2.3		(1.4)	(1.2)		(0.3)			(0.3)
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 income (loss)									
Cash flow hedges (net of tax of $4.7)					4.5	4.5			4.5
Unrecognized pension and other postretirement costs (net of tax of $2.0)					(2.8)	(2.8)			(2.8)
Foreign currency translation (net of tax of $1.5)					(2.4)	(2.4)			(2.4)
Comprehensive income						220.2			219.9
Issuance of common stock		1.3	54.5			55.8			55.8
Purchase of deferred compensation shares	(1.2)					(1.2)			(1.2)
Stock based compensation			4.0			4.0			4.0
Dividends on common stock				(208.7)		(208.7)			(208.7)
Other	(0.1)	0.1	(15.9)	1.6		(14.3)		1.3	(13.0)
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**		**0.0**	**227.4**
Other comprehensive income (loss)									
Cash flow hedges (net of tax of $4.8)					**8.9**	**8.9**			**8.9**

Unrecognized pension and other postretirement costs (net of tax of $5.1)					(6.7)	(6.7)			(6.7)
Comprehensive income						229.6			229.6
Issuance of common stock		0.5	21.7			22.2			22.2
Purchase of deferred compensation shares	(1.0)					(1.0)			(1.0)
Stock based compensation			7.5	(2.1)		5.4			5.4
Dividends on common stock				(211.8)		(211.8)			(211.8)
Other	2.4		9.5	(0.7)		11.2			11.2
Balance at December 31, 2011	**$ (17.1)**	**$ 78.3**	**$ 2,579.1**	**$ 363.6**	**$ (42.5)**	**$ 2,961.4**	**$ 51.1**	**$ 0.1**	**$ 3,012.6**

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

Table of Contents

F. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (Millions)	2011	2010	2009
Operating Activities			
Net income (loss)	**$ 230.5**	$ 223.7	$ (67.5)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Discontinued operations, net of tax	**0.4**	(0.2)	(2.8)
Goodwill impairment loss			291.1
Impairment losses on property, plant, and equipment	**4.6**	43.2	0.7
Depreciation and amortization expense	**250.1**	265.8	230.6
Recoveries and refunds of regulatory assets and liabilities	**56.1**	28.7	40.8
Net unrealized (gains) losses on nonregulated energy contracts	**48.5**	(55.8)	104.2
Nonregulated lower of cost or market inventory adjustments	**11.6**	0.9	44.2
Bad debt expense	**35.0**	48.0	54.6
Pension and other postretirement expense	**60.0**	67.6	72.4
Pension and other postretirement contributions	**(131.5)**	(201.8)	(53.3)
Deferred income taxes and investment tax credits	**175.3**	234.1	58.3
(Gain) loss on sale of assets	**(2.2)**	11.4	24.1
Equity income, net of dividends	**(14.8)**	(14.5)	(16.1)
Other	**32.5**	33.3	37.7
Changes in working capital			
Collateral on deposit	**(17.3)**	163.6	45.5
Accounts receivable and accrued unbilled revenues	**94.1**	97.6	864.8
Inventories	**(28.0)**	51.1	444.1
Other current assets	**46.2**	(85.5)	39.6
Accounts payable	**(37.4)**	(25.8)	(604.7)
Other current liabilities	**(91.8)**	(160.2)	(2.0)
Net cash provided by operating activities	**721.9**	725.2	1,606.3
Investing Activities			
Capital expenditures	**(311.4)**	(258.8)	(444.2)
Proceeds from the sale or disposal of assets	**7.6**	66.0	44.6
Capital contributions to equity method investments	**(37.6)**	(6.9)	(34.1)
Acquisition of compressed natural gas fueling companies, net of cash acquired	**(42.6)**		
Other	**(10.8)**		(7.0)
Net cash used for investing activities	**(394.8)**	(199.7)	(440.7)
Financing Activities			
Short-term debt, net	**303.3**	(212.1)	(815.7)
Redemption of notes payable	**(10.0)**		(157.9)
Proceeds from sale of borrowed natural gas		21.9	162.0
Purchase of natural gas to repay natural gas loans		(6.5)	(445.2)
Issuance of long-term debt	**50.0**	250.0	230.0
Repayment of long-term debt	**(565.8)**	(117.2)	(157.8)
Payment of dividends			
Preferred stock of subsidiary	**(3.1)**	(3.1)	(3.1)
Common stock	**(206.4)**	(186.1)	(206.9)
Issuance of common stock	**4.9**	33.2	
Proceeds from derivative contracts related to divestitures classified as financing activities			33.9
	(31.9)	(157.8)	

Payments made on derivative contracts related to divestitures classified as financing activities			
Other	**(19.4)**	(13.7)	(17.7)
Net cash used for financing activities	**(478.4)**	(391.4)	(1,378.4)
Change in cash and cash equivalents - continuing operations	**(151.3)**	134.1	(212.8)
Change in cash and cash equivalents - discontinued operations			
Net cash provided by investing activities	**0.4**	0.4	3.2
Net change in cash and cash equivalents	**(150.9)**	134.5	(209.6)
Cash and cash equivalents at beginning of year	**179.0**	44.5	254.1
Cash and cash equivalents at end of year	**$ 28.1**	$ 179.0	$ 44.5

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

Table of Contents

G. 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, 2011, included WPS, UPPCO, MGU, MERC, PGL, NSG, 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 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 9, *Investments in Affiliates, at Equity Method.*

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

(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 supplemental disclosure to our statements of cash flows:

(Millions)	2011	2010	2009
Cash paid for interest	**$ 130.7**	$ 138.7	$ 164.8
Cash (received) paid for income taxes	**(80.0)**	(2.2)	19.1

Significant noncash transactions were:

(Millions)	2011	2010	2009
Construction costs funded through accounts payable	**$ 58.6**	$ 18.3	$ 30.4
Equity issued for stock-based compensation plans	**15.8**	3.0	
Equity issued for reinvested dividends	**5.4**	22.6	
Intangible assets (customer contracts) received in exchange for risk management assets			17.0

(f) Revenues and Customer Receivables Revenues related to the sale of energy are recognized when service is provided or energy is delivered to customers and include estimated amounts for services provided but not billed. At December 31, 2011 and 2010, our unbilled revenues were $282.1 million and $339.1 million, respectively. At December 31, 2011, there were no customers or industries that accounted for more than 10% of our revenues. We present revenue net of pass-through taxes on the income statements.

Our utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of prudently incurred electric fuel costs, purchased power costs, and natural gas costs, which allow subsequent adjustments to rates for changes in commodity costs. Other mechanisms also allow recovery for environmental costs, conservation improvement program (CIP) costs, bad debts, and energy conservation and management programs. A summary of significant rate-adjustment mechanisms follows:

Table of Contents

- 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 rules effective January 1, 2011, 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 CIP 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 cost (as defined in the latest rate order) and the amount recovered in rates.

- Decoupling mechanisms were in place at WPS, PGL, NSG, MGU, and UPPCO for 2011. These mechanisms differ state by state and allow utilities to adjust rates going forward to recover or refund all or a portion of the differences between actual and authorized margins.

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 natural gas in storage, liquid propane, and fossil fuels, including coal. Average cost is used to value 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 37% of total inventories at December 31, 2011, and 34% of total inventories at December 31, 2010. The estimated replacement cost of natural gas in inventory at December 31, 2011, and December 31, 2010, exceeded the LIFO cost by approximately $65.7 million and $136.7 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per dekatherm of $3.06 at December 31, 2011, and $4.42 at December 31, 2010.

Inventories at Integrys Energy Services are valued at the lower of cost or market. Integrys Energy Services recorded net write-downs of $11.6 million, $0.9 million, and $44.2 million in 2011, 2010, and 2009, 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. To the extent they are effective, the changes in the values of contracts designated as cash flow hedges are included in other comprehensive income, net of taxes. Fair value hedge ineffectiveness and cash flow hedge ineffectiveness are 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.

Table of Contents

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, 2011, 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 original 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. 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. In addition, 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. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses. 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	**2011**	**2010**	**2009**
WPS Electric	**2.88%**	3.05%	3.04%
WPS Natural gas	**2.22%**	3.28%	3.30%
UPPCO	**3.33%**	3.18%	3.05%
MGU	**2.73%**	3.55%	2.66%
MERC	**3.10%**	3.08%	3.10%
PGL	**3.18%**	3.10%	2.29%
NSG	**2.42%**	2.35%	1.66%

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 6, *Property, Plant, and Equipment*, for details regarding our property, plant, and equipment balances.

(k) Capitalized Interest and AFUDC Our nonregulated subsidiaries capitalize interest for construction projects; however, interest capitalized was not significant during 2011, 2010, and 2009. 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 of capitalized AFUDC is accounted for as other income, and 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 2011, WPS s average AFUDC retail rate was 7.71%, and its average AFUDC wholesale rate was 4.16%. WPS s allowance for equity funds used during construction for 2011, 2010, and 2009 was $0.6 million, $0.7 million, and $5.1 million, respectively. WPS s allowance for borrowed funds used during construction for 2011, 2010, and 2009 was $0.2 million, $0.3 million, and $2.0 million, respectively.

The AFUDC calculation for the other utilities and IBS is determined by the respective state commissions, each with specific requirements. Based on these requirements, the other utilities and IBS did not record significant AFUDC for 2011, 2010, or 2009.

Table of Contents

(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 8, *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. 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. See Note 6, *Property, Plant, and Equipment*, for a discussion of recent impairments related to other long-lived assets.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year, and interim impairment tests when impairment indicators are present. The carrying amount of the reporting unit s goodwill is considered not recoverable if it exceeds the reporting unit s fair value. An impairment loss is recorded for the excess of the carrying value of the goodwill over its implied fair value. For more information on our goodwill and other intangible assets, see Note 10, *Goodwill and Other Intangible Assets*.

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

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

The carrying values of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying values, 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 value 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. Any gains or losses resulting from the retirement of nonutility debt are recorded through current earnings.

(o) Asset Retirement Obligations We recognize legal obligations at fair value 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 14, *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. The tax allocation arrangement equitably allocates the state taxes associated with these combined or consolidated filings.

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 when it is uncertain if 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.

Table of Contents

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. Production tax credits generally reduce the provision for income taxes in the year that electricity from the qualifying facility is generated and sold. Investment tax credits and production tax credits that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset. A valuation allowance is established unless it is more likely than not that the credits will be realized during the carryforward period.

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.

For more information regarding accounting for income taxes, see Note 15, *Income Taxes*.

(q) Guarantees Integrys Energy Group follows the guidance of the Guarantees Topic 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 17, *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 that existed prior to the PELLC merger is being recognized over a 20-year period beginning in 1993. 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 18, *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. Transaction costs should not be considered in the determination of fair value.

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.

Table of Contents

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

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

See Note 23, *Fair Value*, for additional information.

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

ASU 2011-05, Presentation of Comprehensive Income, was issued in June 2011. The guidance requires that the total of comprehensive income, the components of net income, and the components of OCI be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The FASB has deferred the requirement regarding the presentation of reclassification adjustments between OCI and net income on the face of the financial statements. This guidance is effective for our reporting period ending March 31, 2012, and is expected to change the format of our financial statements.

ASU 2011-08, Testing Goodwill for Impairment, was issued in September 2011. The amendments give companies an option to first perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If a company concludes that this is the case, the quantitative impairment test is required. Otherwise, a company can bypass the quantitative impairment test. This guidance is effective for our reporting period ending March 31, 2012, and is not expected to have a significant impact on our financial statements.

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

Table of Contents

NOTE 2 RISK MANAGEMENT ACTIVITIES

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

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

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

Table of Contents

		December 31, 2010	
(Millions)	**Balance Sheet Presentation ***	**Assets from Risk Management Activities**	**Liabilities from Risk Management Activities**
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 2.2	$ 23.6
Natural gas contracts	Long-term	1.6	1.4
FTRs	Current	3.1	0.2
Petroleum product contracts	Current	0.6	
Coal contract	Current		1.2
Coal contract	Long-term	3.7	
Cash flow hedges			
Natural gas contracts	Current		1.0
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	132.0	113.8
Natural gas contracts	Long-term	62.3	57.7
Electric contracts	Current	85.7	122.0
Electric contracts	Long-term	16.5	30.3
Foreign exchange contracts	Current	1.2	1.2
Foreign exchange contracts	Long-term	0.3	0.3
Fair value hedges			
Interest rate swaps	Current	0.9	
Cash flow hedges			
Natural gas contracts	Current	1.6	9.2
Natural gas contracts	Long-term	0.1	0.9
Electric contracts	Current	9.6	17.4
Electric contracts	Long-term	4.9	9.1
	Current	236.9	289.6
	Long-term	89.4	99.7
Total		$ 326.3	$ 389.3

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

The following table shows our cash collateral positions:

(Millions)	**December 31, 2011**	**December 31, 2010**
Cash collateral provided to others	**$ 50.9**	$ 33.3
Cash collateral received from others *	**2.3**	4.5

* Reflected in other current liabilities on the Balance Sheets.

Certain of our derivative and nonderivative commodity instruments contain provisions that could require adequate assurance in the event of a material 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, 2011	December 31, 2010
Integrys Energy Services	**$ 193.8**	$ 219.5
Utility segments	**39.1**	22.1

Table of Contents

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, 2011	December 31, 2010
Collateral that would have been required:			
Integrys Energy Services		**$ 272.3**	$ 295.7
Utility segments		**28.7**	14.1
Collateral already satisfied:			
Integrys Energy Services	Letters of credit	**11.0**	56.9
Collateral remaining:			
Integrys Energy Services		**261.3**	238.8
Utility segments		**28.7**	14.1

Utility Segments

Non-Hedge Derivatives

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

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

	December 31, 2011		December 31, 2010	
	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**1,122.7**	**N/A**	979.9	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**5,077.5**	N/A	5,882.5
Petroleum products (barrels)	**46,872.0**	**N/A**	71,827.0	N/A
Coal contract (millions of tons)	**4.1**	**N/A**	4.9	N/A

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

(Millions)	Financial Statement Presentation		2011	2010
Natural gas contracts	Balance Sheet	Regulatory assets (current)	**$ (11.3)**	$ (1.7)
Natural gas contracts	Balance Sheet	Regulatory assets (long-term)	**(7.6)**	0.1
Natural gas contracts	Balance Sheet	Regulatory liabilities (current)	**8.4**	
FTRs	Balance Sheet	Regulatory assets (current)	**(0.4)**	1.0
FTRs	Balance Sheet	Regulatory liabilities (current)	**(1.3)**	(2.1)

Petroleum product contracts	Balance Sheet	Regulatory assets (current)	**(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 contract	Balance Sheet	Regulatory assets (current)	**(1.3)**	(1.2)
Coal contract	Balance Sheet	Regulatory assets (long-term)	**(4.4)**	
Coal contract	Balance Sheet	Regulatory liabilities (long-term)	**(3.7)**	3.7

(Millions)	**Financial Statement Presentation**		**2009**
Commodity contracts	Balance Sheet	Regulatory assets (current)	$ 122.5
Commodity contracts	Balance Sheet	Regulatory assets (long-term)	7.3
Commodity contracts	Balance Sheet	Regulatory liabilities (current)	(1.0)
Commodity contracts	Income Statement	Utility cost of fuel, natural gas, and purchased power	0.1

Cash Flow Hedges

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

	Purchases	
	December 31, 2011	**December 31, 2010**
Natural gas (millions of therms)	**8.1**	5.4

Table of Contents

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

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

(Millions)	2011	2010	2009
Natural gas contracts	**$ (1.3)**	$ (1.6)	$ (1.4)

Loss Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	Income Statement Presentation	2011	2010	2009
Settled natural gas contracts	Operating and maintenance expense	**$ (1.2)**	$ (0.9)	$ (2.6)

No amounts were reclassified from accumulated OCI into earnings as a result of the discontinuance of cash flow hedge accounting related to these natural gas contracts during 2011, 2010, and 2009. Cash flow hedge ineffectiveness related to these natural gas contracts also was not significant during 2011, 2010, and 2009. When testing for effectiveness, no portion of these derivative instruments was excluded. In the next 12 months, an insignificant loss is expected to be recognized in earnings as the hedged transactions occur.

Nonregulated Segments

Non-Hedge Derivatives

Integrys Energy Services enters into derivative contracts such as futures, forwards, options, and swaps that are not designated as accounting hedges under GAAP. These contracts are used to manage commodity price risk primarily associated with customer-related contracts.

As of July 1, 2011, Integrys Energy Services discontinued the use of cash flow hedge accounting. At December 31, 2011, the amount deferred in accumulated OCI related to cash flow hedges at Integrys Energy Services was a pre-tax loss of $9.9 million. This amount relates to natural gas futures, forwards, and swaps that extend through April 2014, and electric futures, forwards, and swaps that extend through May 2017. This amount will be recognized in earnings as the forecasted transactions occur, or if it becomes probable that the forecasted transactions will not occur.

In the next 12 months, pre-tax losses of $2.0 million and $4.3 million related to the discontinued cash flow hedges of natural gas contracts and electric contracts, respectively, are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative contracts.

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

(Millions)	December 31, 2011 Purchases	Sales	December 31, 2010 Purchases	Sales
Commodity contracts				
Natural gas (therms)	**959.2**	**797.1**	940.6	1,048.4
Electric (kilowatt-hours)	**34,405.7**	**20,374.0**	22,149.4	19,707.0
Foreign exchange contracts (Canadian dollars)	**4.2**	**4.2**	15.5	15.5

Table of Contents

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

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

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

(Millions)	Income Statement Presentation	2009
Commodity contracts	Nonregulated revenue	$ (5.1)
Commodity contracts	Nonregulated revenue (reclassified from accumulated OCI)	(3.2)*
Interest rate swaps	Interest expense	(1.7)
Foreign exchange contracts	Nonregulated revenue	(1.8)
Total		$ (11.8)

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

Fair Value Hedges

At PELLC, an interest rate swap designated as a fair value hedge was used to hedge changes in the fair value of $50.0 million of the $325.0 million Series A 6.9% notes. The interest rate swap and the notes were settled in January 2011. The changes in the fair value of this hedge were recognized in earnings, as were the changes in fair value of the hedged item. Unrealized gains (losses) related to the fair value hedge and the related hedged item are shown in the table below:

(Millions)	Income Statement Presentation	2011	2010	2009
Interest rate swap	Interest expense	**$**	$ (1.7)	$ (0.6)
Debt hedged by swap	Interest expense		1.7	0.6
Total		**$**	$	$

Fair value hedge ineffectiveness recorded in interest expense on the Statements of Income was not significant for 2011, 2010, and 2009. No amounts were excluded from effectiveness testing related to the interest rate swap during 2011, 2010, and 2009.

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-related contracts.

In addition, we entered into interest rate swaps that were designated as cash flow hedges to hedge the variability in forecasted interest payments on debt issuance. The swaps were terminated when the related debt was issued.

Integrys Energy Services had the following notional volumes of outstanding contracts that were designated as cash flow hedges:

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

Table of Contents

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

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

Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)		
(Millions)		2009
Commodity contracts	$	(60.0)
Interest rate swaps		3.2
Total	$	(56.8)

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

(Millions)	Income Statement Presentation		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)**		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		**$**	**(6.7)**	$	(47.5)

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

(Millions)	Income Statement Presentation		2009
Settled/Realized			
Commodity contracts	Nonregulated revenue	$	(107.3)
Interest rate swaps	Interest expense		1.2
Hedge Designation Discontinued			
Commodity contracts	Nonregulated revenue		2.7
Total		$	(103.4)

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

(Millions)	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)

Loss Recognized in Income on Derivative Instruments

	(Ineffective Portion and Amount Excluded from Effectiveness Testing)	
(Millions)	**Income Statement Presentation**	**2009**
Commodity contracts	Nonregulated revenue	$ (1.1)

Table of Contents

NOTE 3 RESTRUCTURING EXPENSE

Reductions in Workforce

In an effort to remove costs from our operations, we developed a plan at the end of 2009 that included reductions in our workforce. In connection with this plan, employee-related and consulting costs were included in the restructuring expense line item on the Statements of Income. The restructuring costs were distributed across our segments as follows:

(Millions)	2011	2010	2009
Electric utility	**$ 0.2**	$ (0.3)	$ 8.6
Natural gas utility		(0.2)	6.9
Integrys Energy Services			1.7
Holding company and other		0.1	0.8
Total restructuring expense	**$ 0.2**	$ (0.4)	$ 18.0

The following table summarizes the activity related to these restructuring costs:

(Millions)	2011	2010
Accrued restructuring costs at beginning of period	**$ 0.2**	$ 18.0
Add: Adjustments to accrual during the period	*	(0.1)*
Deduct: Cash payments	**0.2**	17.7
Accrued restructuring costs at end of period	**$**	$ 0.2

* In 2010, restructuring costs of $0.3 million were billed to certain companies in accordance with provisions in the operating agreements with these companies that allow us to recover a portion of our administrative and general expenses. In 2011, the amounts previously billed to these companies were adjusted and reduced by $0.2 million.

We do not expect to recognize any additional restructuring costs associated with this plan in future periods.

Integrys Energy Services Strategy Change

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

(Millions)	2011	2010	2009
Employee-related costs	**$ (0.1)**	$ 1.1	$ 10.1
Professional fees		6.4	9.2
Software write-offs			5.3
Accelerated lease costs and depreciation	**1.9**	0.4	0.6
Miscellaneous		0.4	0.3
Total restructuring expense	**$ 1.8**	$ 8.3	$ 25.5

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

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

(Millions)	2011	2010
Accrued employee-related costs at beginning of period	**$ 0.3**	$ 8.2
Add: Employee-related costs expensed	**(0.1)**	1.1
Deduct: Cash payments	**0.2**	9.0
Accrued employee-related costs at end of period	**$**	$ 0.3

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

Table of Contents

NOTE 4 ACQUISITION

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. This amount is subject to post-closing working capital adjustments. The total cash payment for this transaction was $42.6 million, which was net of cash acquired of approximately $7 million.

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 10, *Goodwill and Other Intangible Assets*, for more information related to this acquisition.

NOTE 5 DISPOSITIONS

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.

The following table shows the carrying values of the major classes of assets and liabilities included in the sale at the June 2010 closing date:

(Millions)		
Current assets from risk management activities	$	14.0
Other current assets		2.2
Long-term assets from risk management activities		13.8
Other long-term assets		1.9

Total assets	$	31.9
Current liabilities from risk management activities	$	35.2
Long-term liabilities from risk management activities		27.3
Total liabilities	$	62.5

In addition to the above recognized assets and liabilities, commodity contracts not accounted for as derivative instruments were also transferred to the buyer.

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, including a natural gas storage contract. In conjunction with the sale, Integrys Energy Services entered into derivative contracts with the buyer of the portfolio to reestablish the economic hedges for the retained United States retail business, at the same prices and other terms originally executed through Integrys Energy Services Canadian natural gas and electric power portfolio. In May 2010, Integrys Energy Services completed the sale of its remaining Canadian wholesale electric marketing and trading portfolio. The pre-tax losses on the sales in both 2010 and 2009 were $0.4 million and were reported as a component of net (gain) loss on Integrys Energy Services dispositions related to strategy change in the income statement.

Table of Contents

The following table shows the carrying values of the major classes of assets and liabilities included in the sale at the May 2010 closing date:

(Millions)		
Current assets from risk management activities	$	13.8
Long-term assets from risk management activities		10.5
Total assets	$	24.3
Current liabilities from risk management activities	$	15.2
Long-term liabilities from risk management activities		9.5
Total liabilities	$	24.7

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 in 2010 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 in 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, upon which time the corresponding mirror transactions terminated. As of December 31, 2010, a vast majority of the commodity contracts had been terminated, with the remaining to be settled through the normal course of business, at which time the corresponding mirror transactions will terminate.

The following table shows the carrying values of the major classes of assets and liabilities included in the sale at the March 2010 closing date:

(Millions)		
Current assets from risk management activities	$	1,375.5
Long-term assets from risk management activities		683.3
Total assets	$	2,058.8
Current liabilities from risk management activities	$	1,389.8
Long-term liabilities from risk management activities		654.3
Total liabilities	$	2,044.1

In addition to the above recognized assets and liabilities, commodity contracts not accounted for as derivative instruments were also transferred to the buyer.

In conjunction with the sale, Integrys Energy Services entered into derivative contracts with the buyer to reestablish 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 will retain counterparty default risk with approximately 50% of the counterparties to the commodity contracts novated, of which the majority will have expired by the end of the first quarter of 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 have ended as of December 31, 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 in 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

Table of Contents

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 in the income statement.

The carrying values of the major classes of assets and liabilities included in the sales as of the multiple 2010 closing dates were as follows:

(Millions)		
Inventories	$	0.1
Property, plant, and equipment, net		25.1
Other long-term assets		1.3
Total assets	$	26.5
Other current liabilities	$	0.1
Asset retirement obligations		0.3
Total liabilities	$	0.4

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 carrying value of inventories included in the sales was $1.8 million as of the closing date.

The pre-tax losses 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 and 2009 was $2.0 million and $28.5 million, respectively, and were reported as a component of net (gain) loss on Integrys Energy Services dispositions related to strategy change in the income statement.

Discontinued Operations Resulting from Integrys Energy Services Strategy Change

Energy Management Consulting Business

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

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

During 2009, Integrys Energy Services completed the sale of its energy management consulting business and received proceeds of $4.7 million. This business provided consulting services relating to long-term strategies for managing energy costs for its customers. The historical results of this business were not significant. The gain on the sale of this business reported in discontinued operations during the third quarter of 2009 was $3.9 million ($2.4 million after tax).

Other Discontinued Operations

Peoples Energy Production Company

During 2011, we recorded a $0.5 million after-tax net loss in discontinued operations when we remeasured an unrecognized tax benefit liability related to the 2007 sale of Peoples Energy Production Company, including an adjustment for a lapse in the statute of limitations for certain states associated with these tax filings.

WPS Niagara Generation, LLC

During 2009, Integrys Energy Services recorded a $0.4 million after-tax gain in discontinued operations related to a refund received in connection with the overpayment for auxiliary power service in prior years.

Table of Contents

NOTE 6 PROPERTY, PLANT, AND EQUIPMENT

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

(Millions)	2011	2010
Electric utility	**$ 3,139.7**	$ 3,095.5
Natural gas utility	**4,751.4**	4,506.3
Total utility plant	**7,891.1**	7,601.8
Less: Accumulated depreciation	**2,910.1**	2,794.2
Net	**4,981.0**	4,807.6
Construction work in progress	**62.0**	39.5
Net utility plant	**5,043.0**	4,847.1
Nonutility plant	**130.4**	143.9
Less: Accumulated depreciation	**68.7**	70.2
Net	**61.7**	73.7
Construction work in progress	**2.7**	1.6
Net nonutility plant	**64.4**	75.3
Integrys Energy Services energy assets	**100.6**	98.9
Integrys Energy Services other	**20.0**	21.1
Other nonregulated	**8.0**	6.0
Total nonregulated property, plant, and equipment	**128.6**	126.0
Less: Accumulated depreciation	**39.9**	35.8
Net	**88.7**	90.2
Construction work in progress	**3.0**	0.8
Net nonregulated property, plant, and equipment	**91.7**	91.0
Total property, plant, and equipment	**$ 5,199.1**	$ 5,013.4

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist. During the fourth quarter of 2011, Integrys Energy Services recorded a pre-tax non-cash impairment loss of $4.6 million related to its Winnebago Energy Center, a landfill-gas-to-electric facility. During the third quarter of 2010, Integrys Energy Services recorded a pre-tax non-cash impairment loss of $43.2 million related to its three natural gas-fired generation plants (Beaver Falls Generation, Syracuse Generation, and Combined Locks Energy Center). The impairment charges resulted from lower estimated future cash flows for these facilities and were primarily driven by forward energy and capacity prices. The impairment charges were reported as impairment losses on property, plant, and equipment in the income statements. The fair values of the facilities were determined primarily using the income approach, which was based on discounted cash flows that were derived from internal forecasts using externally supplied forward energy and capacity pricing curves. Renewable energy credits were also considered for the Winnebago Energy Center. Other assumptions included forecasted operating expenses, forecasted capital additions, anticipated working capital requirements, and the discount rate. The discount rate represents the estimated cost of capital appropriate for each facility and is also based upon the cash flow period used for the fair value assessment. The discount rate used for the Winnebago Energy Center impairment analysis in 2011 was 7.5%. The discount rate used for the natural gas-fired plants impairment analysis in 2010 was 10%.

NOTE 7 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 recorded its proportionate share of significant jointly owned electric generating facilities on the balance sheets, and the amounts were as follows at December 31, 2011:

(Millions, except for percentages and megawatts)	Weston 4	Columbia Energy Center Units 1 and 2	Edgewater Unit No. 4
Ownership	70.0%	31.8%	31.8%
WPS s share of rated capacity (megawatts)	374.5	335.2	105.0
Utility plant in service	$573.3	$167.8	$39.8
Accumulated depreciation	$78.5	$106.6	$25.4
In-service date	2008	1975 and 1978	1969

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.

Table of Contents

NOTE 8 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. These rates are based on specific ratemaking decisions over 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 for such costs, we believe it is probable that our utility subsidiaries will continue to recover from customers the regulatory assets described below.

Most of our regulatory assets are earning a return, except for costs associated with WPS environmental remediation, unamortized loss on reacquired debt at WPS, PGL, NSG, and UPPCO, the Weston 3 lightning strike, and MERC s conservation program. The carrying costs related to the regulatory assets not earning a return are borne by our shareholders. The following regulatory assets and liabilities were reflected in our balance sheets as of December 31:

(Millions)	2011	2010	See Note
Regulatory assets			
Unrecognized pension and other postretirement benefit costs	**$ 733.6**	$ 544.5	18
Environmental remediation costs (net of insurance recoveries) (1)	**626.8**	653.0	16
Merger and acquisition related pension and other postretirement benefit costs (2)	**121.9**	133.8	
Derivatives	**59.0**	34.1	1(h)
Asset retirement obligations	**58.1**	47.6	14
Income tax related items	**37.9**	28.1	15
Decoupling	**33.3**	50.5	26
De Pere Energy Center (3)	**28.6**	31.0	
Unamortized loss on reacquired debt (4)	**18.8**	14.6	1(n)
Conservation program costs (5)	**13.3**	15.3	
Weston 3 lightning strike (6)	**10.9**	14.5	
Other	**41.4**	46.0	
Total	**$ 1,783.6**	$ 1,613.0	
Balance Sheet Presentation			
Current	**$ 125.1**	$ 117.9	
Long-term	**1,658.5**	1,495.1	
Total	**$ 1,783.6**	$ 1,613.0	
Regulatory liabilities			
Removal costs (7)	**$ 298.0**	$ 278.1	
Energy costs refundable through rate adjustments (8)	**30.4**	51.8	
Unrecognized pension and other postretirement benefit costs	**18.4**	20.0	18
Decoupling	**17.2**	8.1	26
Uncollectible expense	**11.3**	8.3	26
Derivatives	**9.3**	6.0	1(h)
Energy Efficiency Program (5)	**5.4**	7.2	
Other	**10.0**	12.4	
Total	**$ 400.0**	$ 391.9	
Balance Sheet Presentation			
Current	**$ 67.5**	$ 75.7	
Long-term	**332.5**	316.2	
Total	**$ 400.0**	$ 391.9	

(1) As of December 31, 2011, we had not yet made cash expenditures for $615.1 million of these environmental remediation costs. The recovery of environmental remediation costs depends on the timing of the actual expenditures.

(2) Composed of unrecognized benefit costs that existed prior to the PELLC merger and the MERC and MGU acquisitions.

(3) Prior to WPS purchasing the De Pere Energy Center, 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.

(4) Amounts for PGL and NSG are recovered over the term of the replacement debt as authorized by the ICC. WPS is authorized recovery of this regulatory asset through 2015. UPPCO is authorized recovery of this regulatory asset through 2018.

(5) Represents amounts recoverable from and/or refundable to customers related to programs designed to meet energy efficiency standards. MERC is authorized recovery of this regulatory asset through 2012.

Table of Contents

(6) In 2007, a lightning strike caused significant damage to the Weston 3 generating facility. The PSCW approved the deferral of the incremental fuel and purchased power expenses, as well as the non-fuel operating and maintenance expenditures incurred as a result of the outage that were not covered by insurance. WPS is authorized recovery of this regulatory asset through 2014.

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

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

NOTE 9 INVESTMENTS IN AFFILIATES, AT EQUITY METHOD

Investments in corporate joint ventures and other companies accounted for under the equity method at December 31, 2011, and 2010 were as follows:

(Millions)	2011	2010
ATC	**$ 439.4**	$ 416.3
INDU Solar Holdings, LLC	**28.4**	0.1
WRPC	**7.7**	8.1
Other	**0.8**	1.0
Investments in affiliates, at equity method	**$ 476.3**	$ 425.5

Investments in affiliates accounted for under the equity method are included in other long-term assets on the Balance Sheets, and the equity income is recorded in miscellaneous income on the Statements of Income. We are taxed on ATC s equity income, due to the tax flow-through nature of ATC s business structure. Accordingly, our provision for income taxes includes taxes on ATC s equity income.

ATC

Our electric transmission investment segment consists of WPS Investments LLC s ownership interest in ATC, which was approximately 34% at December 31, 2011. ATC is a for-profit, transmission-only company regulated by FERC. ATC owns, maintains, monitors, and operates electric transmission assets in portions of Wisconsin, Michigan, Minnesota, and Illinois.

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

(Millions)	2011	2010	2009

Balance at the beginning of period	**$**	**416.3**	$	395.9	$	346.9
Add: Equity in net income		**79.1**		77.6		75.3
Add: Capital contributions		**8.5**		6.8		34.1
Less: Dividends received		**64.5**		64.0		60.4
Balance at the end of period	**$**	**439.4**	$	416.3	$	395.9

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)		**2011**		**2010**		**2009**
Total charges to ATC for services and construction	**$**	**13.5**	$	14.0	$	10.1
Total costs for network transmission service provided by ATC		**102.7**		103.0		90.7

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, and Arizona 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)		**2011**		**2010**
Balance at the beginning of period	**$**	**0.1**	$	
Add: Equity in net loss		**(0.7)**		(0.4)
Add: Capital contributions		**29.0**		0.5
Balance at the end of period	**$**	**28.4**	$	0.1

Table of Contents

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)	2011	2010	2009
Balance at the beginning of period	**$ 8.1**	$ 8.5	$ 8.4
Add: Equity in net income	**0.9**	1.0	1.0
Less: Dividends received	**1.3**	1.4	0.9
Balance at the end of period	**$ 7.7**	$ 8.1	$ 8.5

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)	2011	2010	2009
Revenues from services provided to WRPC	**$ 0.7**	$ 0.6	$ 0.6
Purchases of energy from WRPC	**4.9**	4.7	4.6
Net proceeds from WRPC sales of energy to MISO	**4.7**	4.5	2.6

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)	2011	2010	2009 *
Income statement data			
Revenues	**$ 575.5**	$ 564.1	$ 528.7
Operating expenses	**269.6**	257.6	235.7
Other expense	**81.5**	85.7	77.7
Net income	**$ 224.4**	$ 220.8	$ 215.3
Equity in net income	**$ 79.4**	$ 78.2	$ 76.3

Balance sheet data						
Current assets	**$**	**91.1**	$	62.7	$	54.0
Noncurrent assets		**3,120.5**		2,906.2		2,785.5
Total assets	**$**	**3,211.6**	$	2,968.9	$	2,839.5
Current liabilities	**$**	**319.9**	$	429.0	$	286.3
Long-term debt		**1,400.0**		1,175.0		1,259.6
Other noncurrent liabilities		**88.0**		88.5		80.1
Shareholders equity		**1,403.7**		1,276.4		1,213.5
Total liabilities and shareholders equity	**$**	**3,211.6**	$	2,968.9	$	2,839.5

* Combined financial data for 2009 does not include INDU Solar Holdings, LLC as it was formed in 2010.

Table of Contents

NOTE 10 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, 2011 and 2010:

(Millions)	Natural Gas Segment 2011	Natural Gas Segment 2010	Integrys Energy Services 2011	Integrys Energy Services 2010	Holding Company and Other 2011	Holding Company and Other 2010	Total 2011	Total 2010
Balance as of January 1								
Gross goodwill	**$ 933.5**	$ 933.5	**$ 6.6**	$ 6.6	**$**	$	**$ 940.1**	$ 940.1
Accumulated impairment losses	**(297.6)**	(297.6)					**(297.6)**	(297.6)
Net goodwill	**635.9**	635.9	**6.6**	6.6			**642.5**	642.5
Goodwill acquired					**15.9**		**15.9**	
Balance as of December 31								
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

In the second quarter of 2011, annual impairment tests were completed at all of our reporting units that carried a goodwill balance. No impairments resulted from these tests.

In the first quarter of 2009, the combination of the decline in equity markets as well as the increase in the expected weighted-average cost of capital triggered an interim goodwill impairment analysis. Based upon the results of this analysis, Integrys Energy Group recorded a noncash goodwill impairment loss of $291.1 million ($248.8 million after tax) in the first quarter of 2009, all within the natural gas utility segment. A combination of the income approach and the market approach were used to estimate the fair values of PGL, NSG, MERC, and MGU. The income approach was used to estimate the fair value of Integrys Energy Services. Key factors contributing to the impairment charge included disruptions in the global credit and equity markets and the resulting increase in the weighted-average cost of capital used to value the natural gas utility operations, and the negative impact that the global decline in equity markets had on the valuation of natural gas distribution companies in general.

In connection with the acquisition of Trillium and Pinnacle, we recorded goodwill of $15.9 million and intangible assets of $20.2 million in the third quarter of 2011. The allocated fair market values and the approximate amortization periods by major intangible asset class were as follows:

	Fair Market Value	Approximate Amortization Period (in years)
Patents	$ 7.2	18
Compressed natural gas fueling contract assets	5.6	10
Customer relationships	1.9	15
Trade names	5.0	Indefinite life
Software	0.5	3

Total	$	20.2

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

Table of Contents

(Millions)	December 31, 2011 Gross Carrying Amount	December 31, 2011 Accumulated Amortization	December 31, 2011 Net	December 31, 2010 Gross Carrying Amount	December 31, 2010 Accumulated Amortization	December 31, 2010 Net
Amortized intangible assets						
Customer-related (1)	**$ 34.5**	**$ (24.8)**	**$ 9.7**	$ 32.6	$ (21.8)	$ 10.8
Natural gas and electric contract assets (2) (3)	**7.8**	**(6.6)**	**1.2**	57.1	(55.0)	2.1
Patents (4)	**7.2**		**7.2**			
Compressed natural gas fueling contract assets (5)	**5.6**	**(0.3)**	**5.3**			
Natural gas and electric contract liabilities (2)				(10.5)	10.5	
Renewable energy credits (6)	**2.8**		**2.8**	2.5		2.5
Nonregulated easements (7)	**3.8**	**(0.7)**	**3.1**	3.8	(0.4)	3.4
Customer-owned equipment modifications (8)	**3.6**	**(0.2)**	**3.4**	1.6	(0.1)	1.5
Emission allowances (9)	**1.7**	**(0.2)**	**1.5**	1.9	(0.2)	1.7
Other	**1.4**	**(0.3)**	**1.1**	0.8	(0.3)	0.5
Total	**$ 68.4**	**$ (33.1)**	**$ 35.3**	$ 89.8	$ (67.3)	$ 22.5
Unamortized intangible assets						
MGU trade name	**$ 5.2**		**$ 5.2**	$ 5.2		$ 5.2
Trillium trade name	**3.5**		**3.5**			
Pinnacle trade name	**1.5**		**1.5**			
Total intangible assets	**$ 78.6**	**$ (33.1)**	**$ 45.5**	$ 95.0	$ (67.3)	$ 27.7

(1) Includes customer relationship assets associated with PELLC s former nonregulated retail natural gas and electric operations, MERC s nonutility ServiceChoice business, and Trillium and Pinnacle compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at December 31, 2011, was approximately 10 years.

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

(3) Includes both short-term and long-term intangible assets related to customer contracts in the amount of $0.5 million and $0.7 million, respectively, at December 31, 2011, and $0.9 million and $1.2 million, respectively, at December 31, 2010. The remaining amortization period at December 31, 2011, was approximately three years.

(4) Includes 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, 2011, was approximately 18 years.

(5) Represents the fair value of Trillium and Pinnacle compressed natural gas customer fueling contracts acquired in September 2011. The remaining amortization period at December 31, 2011, was approximately 9 years.

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

(7) 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, 2011, of approximately 12 years.

(8) Relates to modifications to customer-owned equipment that allows the end-use customer of a pipeline to accept landfill gas. These intangible assets are amortized on a straight-line basis, with a remaining weighted average amortization period at December 31, 2011, of approximately 12 years.

(9) Emission allowances do not have a contractual term or expiration date. If the EPA s Cross State Air Pollution Rule, which was stayed in December 2011, is reinstated, it will affect our ability to use certain existing emission allowances in the future. See Note 16, *Commitments and Contingencies*, for more information.

Amortization recorded as a component of nonregulated cost of sales in the Statements of Income for the years ended December 31, 2011, 2010, and 2009, was $1.4 million, $4.9 million, and $8.9 million, respectively.

Table of Contents

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

(Millions)		
For year ending December 31, 2012	$	4.8
For year ending December 31, 2013		2.2
For year ending December 31, 2014		1.7
For year ending December 31, 2015		1.3
For year ending December 31, 2016		1.0

Amortization expense recorded as a component of depreciation and amortization expense in the Statements of Income for the years ended December 31, 2011, 2010, and 2009, was $3.4 million, $3.9 million, and $6.3 million, respectively.

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

(Millions)		
For year ending December 31, 2012	$	2.7
For year ending December 31, 2013		2.1
For year ending December 31, 2014		1.8
For year ending December 31, 2015		1.6
For year ending December 31, 2016		1.5

NOTE 11 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 $12.6 million, $15.2 million, and $16.9 million in 2011, 2010, and 2009, respectively. Future minimum rental obligations under non-cancelable operating leases are payable as follows:

Year ending December 31 (Millions)		
2012	$	8.5
2013		8.8
2014		5.0
2015		4.1
2016		4.0
Later years		51.2
Total payments	$	81.6

NOTE 12 SHORT-TERM DEBT AND LINES OF CREDIT

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

(Millions, except percentages)	2011	2010	2009
Commercial paper outstanding	**$ 303.3**		$ 212.1
Average discount rate on outstanding commercial paper	**0.31%**		0.52%
Short-term notes payable outstanding		$ 10.0	$ 10.0
Average interest rate on short-term notes payable outstanding		0.32%	0.18%

The commercial paper outstanding at December 31, 2011, had maturity dates ranging from January 3, 2012 through January 26, 2012.

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

(Millions)	2011	2010	2009
Average amount of commercial paper outstanding	**$ 134.9**	$ 66.9	$ 193.8
Average amount of borrowings outstanding under revolving credit facilities			114.5
Average amount of short-term notes payable outstanding	**3.6**	10.0	48.0

Table of Contents

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our short-term debt, lines of credit, and remaining available capacity as of December 31:

(Millions)	Maturity	2011	2010
Revolving credit facility (Integrys Energy Group) (1)	04/23/13	**$ 735.0**	$ 735.0
Revolving credit facility (Integrys Energy Group) (2)	06/09/11		500.0
Revolving credit facility (Integrys Energy Group) (3)	05/17/16	**200.0**	
Revolving credit facility (Integrys Energy Group) (3)	05/17/14	**275.0**	
Revolving credit facility (WPS) (1)	04/23/13	**115.0**	115.0
Revolving credit facility (WPS) (4)	05/15/12	**135.0**	
Revolving credit facility (PELLC) (2)	06/13/11		400.0
Revolving credit facility (PGL) (1)	04/23/13	**250.0**	250.0
Revolving short-term notes payable (WPS) (2)	05/13/11		10.0
Total short-term credit capacity		**$ 1,710.0**	$ 2,010.0
Less:			
Letters of credit issued inside credit facilities		**33.7**	64.9
Loans outstanding under credit agreements and notes payable			10.0
Commercial paper outstanding		**303.3**	
Available capacity under existing agreements		**$ 1,373.0**	$ 1,935.1

(1) Supports commercial paper borrowing program.

(2) These credit facilities and short-term note payable were terminated/repaid in the second quarter of 2011.

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

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

At December 31, 2011, we and each of our subsidiaries were in compliance with all respective financial covenants related to outstanding short-term debt. Our revolving credit agreements and those of certain of our subsidiaries contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%, excluding non-recourse debt. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

Table of Contents

NOTE 13 LONG-TERM DEBT

(Millions)				December 31 2011	2010
WPS First Mortgage Bonds (1)					
	Series	Year Due			
	7.125%	2023		**$ 0.1**	$ 0.1
WPS Senior Notes (1) (2) (3)					
	Series	Year Due			
	6.125%	2011			150.0
	4.875%	2012		**150.0**	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
UPPCO First Mortgage Bonds (4)					
	Series	Year Due			
	9.32%	2021			9.4
PELLC Unsecured Senior Note (5)					
	Series	Year Due			
	6.90%	2011			325.0
Fair value hedge adjustment					0.9
PGL Fixed First and Refunding Mortgage Bonds (6)					
	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**	
PGL Adjustable First and Refunding Mortgage Bonds (7)					
	Series	Year Due			
	OO	2037			51.0
NSG First Mortgage Bonds (8)					
	Series	Year Due			
	M, 5.00%	2028		**28.2**	28.3
	N-2, 4.625%	2013		**40.0**	40.0
	O, 7.00%	2013		**6.5**	6.5
Integrys Energy Group Unsecured Senior Notes (9)					
	Series	Year Due			

	5.375%	2012	**100.0**	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 (10)				
	Series	Year Due		
	6.11%	2066	**269.8**	300.0
Other term loan (11)			**27.0**	27.0
Total			**2,123.6**	2,640.2
Unamortized discount and premium on bonds and debt			**(1.6)**	(1.7)
Total debt			**2,122.0**	2,638.5
Less current portion			**(250.0)**	(476.9)
Total long-term debt			**$ 1,872.0**	$ 2,161.6

Table of Contents

---

(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 non-collateralized if WPS retires all of its outstanding First Mortgage Bonds and no new mortgage indenture is put in place.

(2) In August 2011, WPS s $150.0 million of 6.125% Senior Notes matured, and the outstanding principal balance was repaid.

(3) In December 2012, WPS s 4.875% Senior Notes will mature. As a result, the $150.0 million balance of these notes was included in current portion of long-term debt on Integrys Energy Group s Consolidated Balance Sheets at December 31, 2011.

(4) In November 2011, UPPCO bought back its $9.4 million of 9.32% First Mortgage Bonds that were due in November 2021.

(5) In January 2011, PELLC s 6.9% unsecured Senior Notes matured, and the outstanding principal balance was repaid. In January 2011, Integrys Energy Group settled the interest rate swap designated as a fair value hedge associated with $50.0 million of the senior notes. See Note 2, *Risk Management Activities*, for more information.

(6) 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 November 2011, PGL issued $50.0 million of 2.21% Series XX First Mortgage Bonds. These bonds are due in November 2016.

(7) In August 2011, PGL bought back its $51.0 million of Adjustable Rate, Series OO bonds that were due October 1, 2037.

(8) 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.

(9) In December 2012, the 5.375% Unsecured Senior Notes will mature. As a result, the $100.0 million balance of these notes was included in current portion of long-term debt on Integrys Energy Group s Consolidated Balance Sheets at December 31, 2011.

(10) These Junior Subordinated Notes are considered hybrid instruments with a combination of debt and equity characteristics. In May 2011, we bought back $30.2 million of these Junior Subordinated Notes. Under a replacement capital covenant with the holders of our 4.17% Unsecured Senior Notes due November 1, 2020, any amounts bought back 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.

(11) In April 2001, the Schuylkill County Industrial Development Authority issued $27.0 million of Refunding Tax Exempt Bonds. The proceeds from the bonds were loaned to WPS Westwood Generation, LLC, a subsidiary of Integrys Energy Services. WPS Westwood Generation pays interest monthly to Schuylkill County Industrial Development Authority. The loan has a floating interest rate that is reset weekly. At December 31, 2011, the interest rate was 0.09%. The loan is to be repaid by April 2021. In January 2011, we replaced our guarantee to provide sufficient funds to pay the loan and the related obligations and indemnities on WPS Westwood Generation s obligation with a standby letter of credit. See Note 17, *Guarantees,* for additional information.

At December 31, 2011, we and each of our subsidiaries were in compliance with all respective financial covenants related to outstanding long-term debt. Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. In addition, certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

Table of Contents

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

Year ending December 31 (Millions)		
2012	$	250.0
2013		313.5
2014		100.0
2015		125.0
2016		105.0
Later years		1,230.1
Total payments	$	2,123.6

NOTE 14 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 obligations 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, 2011:

(Millions)		**Utilities**		**Integrys Energy Services**		**Total**
Asset retirement obligations at December 31, 2008	$	178.9	$	0.2(2)	$	179.1
Accretion		9.6		0.1		9.7
Additions and revisions to estimated cash flows		6.3(1)				6.3
Asset retirement obligations at December 31, 2009		194.8		0.3(2)		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(3)				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**(4)		**0.5**		**64.9**
Settlements		**(5.7)**				**(5.7)**
Asset retirement obligations at December 31, 2011	**$**	**396.7**	**$**	**0.5**	**$**	**397.2**

---

(1) This amount includes a $6.3 million asset retirement obligation related to the WPS 99-megawatt Crane Creek wind generation project that became operational in the fourth quarter of 2009. All other adjustments netted to an insignificant amount.

(2) These amounts were classified as held for sale, as they related to the sale of generation assets in Northern Maine, which closed in the first quarter of 2010.

(3) 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 upon an updated depreciation study, as well as an increase in estimated costs.

(4) 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.

Table of Contents

NOTE 15 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)	2011	2010
Deferred income tax assets		
Tax credit carryforwards	**$ 97.6**	$ 108.6
Employee benefits		40.2
Price risk management	**70.0**	32.3
Other	**57.6**	94.1
Total deferred income tax assets	**$ 225.2**	$ 275.2
Valuation allowance	**(8.0)**	(8.2)
Net deferred income tax assets	**$ 217.2**	$ 267.0
Deferred income tax liabilities		
Plant-related	**$ 1,103.0**	$ 955.0
Regulatory deferrals	**43.4**	64.3
Employee benefits	**9.6**	
Other	**37.7**	40.5
Total deferred income tax liabilities	**$ 1,193.7**	$ 1,059.8
Total net deferred income tax liabilities	**$ 976.5**	$ 792.8
Balance Sheet presentation		
Current deferred income tax assets	**$ 94.2**	$ 67.7
Long-term deferred income tax liabilities	**1,070.7**	860.5
Net deferred income tax liabilities	**$ 976.5**	$ 792.8

Net deferred income tax liabilities increased $183.7 million in 2011. The net increase was driven by 100% bonus depreciation being available throughout 2011. 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. Also during 2011, several states signed legislation that impacted the recognition of our deferred income tax assets and liabilities. Illinois made changes to its corporate combined income tax rates, which are effective for the years 2011 through 2024. Michigan replaced its business tax with a state income tax, effective January 1, 2012. The Wisconsin tax code was changed to conform to the federal tax code, retroactive to December 2010. These changes in state income taxes, including regulatory impacts, combined to increase net deferred income tax liabilities by $12.7 million.

Deferred tax credit carryforwards at December 31, 2011, included $74.0 million of alternative minimum tax credits related to tax credits available under Section 45K (formerly Section 29) of the Internal Revenue Code, which can be carried forward indefinitely. Other deferred tax credit carryforwards included $15.0 million of general business credits, which have a carryforward period of 20 years, with the majority of the general business credits to expire in 2028, $7.6 million of foreign tax credits, which have a carryforward period of 10 years, with the majority of the foreign tax credits to expire in 2020, and $1.0 million of state tax credits, which have a carryforward period of 5 years, with the majority of the state tax credits to expire after 2016.

At December 31, 2011, we had deferred income tax assets of $16.9 million reflecting state operating loss carryforwards. The majority of the state operating loss carryforwards will be used over a 20 year period starting in 2012. If the remaining deferred tax assets are not used to offset future state taxable income, they will expire between 2012 and 2029 as follows:

2012 through 2017	$	0.1 million
2018 through 2023	$	3.4 million
2024 through 2029	$	2.9 million

Valuation allowances are established for certain state operating losses and federal tax credits based on our projected ability to realize the benefit of these losses by offsetting future taxable income. Realization is dependent on generating sufficient taxable income prior to expiration. As of December 31, 2011, the entire valuation allowance was related to noncurrent deferred income tax assets. There was no significant change in the valuation allowance during 2011.

Table of Contents

Regulated utilities record certain adjustments related to deferred income taxes to regulatory assets and liabilities. As the related temporary differences reverse, the regulated utilities are prospectively refunding taxes to or collecting taxes from customers for which deferred taxes were recorded in prior years at rates potentially different than current rates or upon enactment of changes in tax law. The net regulatory asset for these and other regulatory tax effects totaled $31.2 million and $16.2 million at December 31, 2011, and 2010, respectively.

Income Before Taxes

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

	For the Years Ended December 31,		
(Millions)	**2011**	**2010**	**2009**
Domestic	**$ 364.9**	$ 361.1	$ 13.1
Foreign	**(0.1)**	10.6	0.3
Total income before taxes	**$ 364.8**	$ 371.7	$ 13.4

Provision for Income Tax Expense

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

(Millions)	**2011**	**2010**	**2009**
Current provision			
Federal	**$ (44.6)**	$ (83.7)	$ 1.9
State	**5.8**	(10.8)	14.1
Foreign	**(0.2)**	6.8	7.1
Total current provision	**(39.0)**	(87.7)	23.1
Deferred provision			
Federal	**159.7**	216.2	62.9
State	**14.8**	25.3	4.1
Foreign	**0.1**	(3.8)	(7.0)
Total deferred provision	**174.6**	237.7	60.0
Unrecognized tax benefits	**0.9**	(0.6)	(2.0)
Penalties	**0.7**		
Investment tax credits, net	**(1.1)**	(0.9)	(1.1)
Interest	**(2.2)**	(0.3)	3.7
Total provision for income taxes related to continuing operations	**133.9**	148.2	83.7
Discontinued operations	**0.5**	0.2	1.7
Total	**$ 134.4**	$ 148.4	$ 85.4

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.

	2011		2010		2009	
(Millions, except for percentages)	**Rate**	**Amount**	**Rate**	**Amount**	**Rate**	**Amount**
Statutory federal income tax	**35.0%**	**$ 127.7**	35.0%	$ 130.1	35.0%	$ 4.7
State income taxes, net	**5.3**	**19.2**	5.1	19.1	105.2	14.1
Plant-related	**0.5**	**1.7**		0.1	(12.7)	(1.7)
Unrecognized tax benefits and interest	**0.2**	**0.6**	(0.2)	(0.9)	12.7	1.7
Goodwill					486.6	65.2
Investment tax credit amortization	**(0.5)**	**(1.8)**	(0.5)	(1.8)	(19.4)	(2.6)
Federal tax credits	**(1.9)**	**(7.1)**	(1.8)	(6.7)	8.2	1.1
Benefits and compensation	**(2.3)**	**(8.4)**	1.3	5.0	(26.9)	(3.6)
Other differences, net	**0.4**	**2.0**	1.0	3.3	35.9	4.8
Effective income tax	**36.7%**	**$ 133.9**	39.9%	$ 148.2	624.6%	$ 83.7

Table of Contents

Unrecognized Tax Benefits

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

(Millions)	2011	2010	2009
Balance at January 1	**$ 30.4**	$ 31.8	$ 22.4
Increase related to tax positions taken in prior years	**3.1**	9.2	10.2
Decrease related to tax positions taken in prior years	**(1.6)**	(10.6)	(0.2)
Increase related to tax positions taken in current year	**0.9**		
Decrease related to tax positions taken in current year			(0.1)
Decrease related to settlements	**(9.4)**		(0.3)
Decrease related to lapse of statutes	**(1.0)**		(0.2)
Balance at December 31	**$ 22.4**	$ 30.4	$ 31.8

We had accrued interest of $5.0 million and accrued penalties of $3.6 million related to unrecognized tax benefits at December 31, 2011. We had accrued interest of $6.9 million and accrued penalties of $3.0 million related to unrecognized tax benefits at December 31, 2010.

As of December 31, 2011, recognition in subsequent periods of $5.1 million of unrecognized tax benefits related to continuing operations could affect our effective tax rate. Also, recognition in subsequent periods of $9.7 million of unrecognized tax benefits related to discontinued operations could affect our provision for income taxes.

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 2011, we effectively settled the majority of our IRS audits for the 2004 through 2008 tax years, which decreased our liability for unrecognized tax benefits by $9.4 million. In 2011, the IRS commenced examinations of tax years 2009 and 2010.

We file state tax returns based on income in our major 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 by tax authorities for years prior to 2007. As of December 31, 2011, we were subject to examination by state or local tax authorities for the 2007 through 2010 tax years. As of December 31, 2011, our earliest open tax years that were subject to examination by state taxing authorities in our major operating jurisdictions were as follows:

State	Year
Illinois	2003
Wisconsin	2005
Michigan	2007
Minnesota	2007

During 2011, Wisconsin commenced an examination of tax years 2007 and 2008. During 2011, the Illinois taxing authority continued its examination of the 2007 tax year, which began in 2010. The Illinois taxing authority also continued its examination of the 2003 through 2006 tax years of PELLC and its consolidated subsidiaries, which began in 2007.

As of December 31, 2011, 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 2007.

In the next 12 months, it is 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 decrease in unrecognized tax benefits of as much as $13.0 million.

NOTE 16 COMMITMENTS AND CONTINGENCIES

Commodity Purchase Obligations and Purchase Order Commitments

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

Table of Contents

The purchase obligations described below were as of December 31, 2011.

- The electric utility segment had obligations of $167.0 million related to coal supply and transportation that extend through 2016, obligations of $1,311.8 million for either capacity or energy related to purchased power that extend through 2027, and obligations of $5.4 million for other commodities that extend through 2013.
- The natural gas utility segment had obligations of $905.2 million related to natural gas supply and transportation contracts that extend through 2028.
- Integrys Energy Services had obligations of $279.6 million, primarily related to electricity and natural gas supply contracts that extend through 2020.
- We and our subsidiaries also had commitments of $418.2 million in the form of purchase orders issued to various vendors that relate to normal business operations, including construction projects.

Environmental

Clean Air Act (CAA) New Source Review Issues

Weston and Pulliam Plants:

In November 2009, the EPA issued a Notice of Violation (NOV) to WPS alleging violations of the CAA s New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. WPS continues to meet with the EPA and exchange proposals on a possible resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In May 2010, WPS received from the Sierra Club a Notice of Intent (NOI) to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. WPS is working on a possible resolution with the Sierra Club and the EPA. We are currently unable to estimate the possible loss or range of loss related to this matter.

Columbia and Edgewater Plants:

In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants (including WPS). The NOV alleges violations of the CAA s New Source Review requirements related to certain projects completed at those plants. WP&L and the other joint owners exchanged proposals with the EPA on a possible resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Columbia plant did not comply with the CAA. While the previous stay has been lifted and the case is moving forward to a December 2012 trial, the Sierra Club continues to participate in settlement negotiations with the EPA and the joint owners of the Columbia plant to seek resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Edgewater plant did not comply with the CAA. The previous stay of this case has been extended through mid-April 2012 and settlement negotiations with the Sierra Club, the EPA, and the joint owners of the Edgewater plant continue. We are currently unable to estimate the possible loss or range of loss related to this matter.

EPA Settlements with Other Utilities:

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

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

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

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

Table of Contents

Weston Air Permits

Weston 4 Construction Permit:

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

Weston Title V Air Permit:

In November 2010, the WDNR provided a draft revised permit. WPS objected to proposed changes in mercury limits and requirements on the boiler as beyond the authority of the WDNR. WPS and the WDNR continue to meet to resolve these issues. On September 14, 2011, the WDNR issued a draft revised permit and a request for public comments. WPS filed comments objecting to certain provisions in the draft permit. We do not expect this matter to have a material impact on our financial statements.

WDNR Issued NOVs:

Since 2008, WPS received four NOVs from the WDNR alleging various violations of the different air permits for the entire Weston plant, Weston 4, Weston 1, and Weston 2, as well as one NOV for a clerical error involving pages missing from a quarterly report for Weston. Corrective actions have been taken for the events in the five NOVs. On December 20, 2011, the WDNR dismissed two of the NOVs and referred the other three NOVs to the state Justice Department for enforcement. We do not expect this matter to have a material impact on our financial statements.

Pulliam Title V Air Permit

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

WPS also challenged the permit in a contested case proceeding and Petition for Judicial Review. The Petition was dismissed in an order remanding the matter to the WDNR. In February 2011, the WDNR granted a contested case proceeding before an Administrative Law Judge on the issues raised by WPS, which included averaging times in the emission limits in the permit. WPS participated in the contested case proceeding on October 11 and 12, 2011. On December 7, 2011, the Administrative Law Judge did not require the WDNR to insert averaging times as WPS had argued for. WPS has decided not to appeal.

In October 2010, WPS received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA based on what the Sierra Club alleges to be the EPA s unreasonable delay in performing its duties related to the grant or denial of the permit. WPS received notification that the Sierra Club filed suit against the EPA in April 2011. WPS intervened in the case as a necessary party to protect its interests. The WDNR sent the proposed permit to the EPA for a 45-day review, which allowed the parties to enter into a settlement agreement that has not yet been entered by the court.

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

Columbia Title V Air Permit

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

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

In September 2010, the WDNR issued a draft construction permit and a draft revised Title V permit in response to the EPA s order. In November 2010, the EPA notified the WDNR that the EPA does not believe the WDNR s proposal is responsive to the order. In January 2011, the WDNR issued a letter stating that upon review of the submitted public comments, the WDNR has determined not to issue the draft permits that were proposed to respond to the EPA s order. In February 2011, the Sierra Club filed for a declaratory action, claiming that the EPA had to assert jurisdiction over the permits. In May 2011, the WDNR issued a second draft Title V permit in response to the EPA s order. WPS is monitoring this situation with WP&L and meeting with the WDNR. We do not expect this matter to have a material impact on our financial statements.

Table of Contents

Mercury and Interstate Air Quality Rules

Mercury:

The State of Wisconsin s mercury rule, Chapter NR 446, requires a 40% reduction from the 2002 through 2004 baseline mercury emissions in Phase I, beginning January 1, 2010, through the end of 2014. In Phase II, which begins in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90%. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts but less than 150 megawatts must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of December 31, 2011, WPS estimates capital costs of approximately $2 million, which includes estimates for both wholly owned and jointly owned plants, to achieve the required Phase I and Phase II reductions. The capital costs are expected to be recovered in future rate cases.

In December 2011, the EPA issued the final Utility Maximum Achievable Control Technology rule that will regulate emissions of mercury and other hazardous air pollutants. The requirements and impact of the final rule are being evaluated. We do not anticipate the impact of this rule to be significant. We expect to recover future compliance costs in future rates.

Sulfur Dioxide and Nitrogen Oxide:

The EPA issued the Clean Air Interstate Rule (CAIR) in 2005 in order to reduce sulfur dioxide and nitrogen oxide emissions from utility boilers located in 29 states, including Wisconsin, Michigan, Pennsylvania, and New York. In July 2008, the United States Court of Appeals (Court of Appeals) issued a decision vacating CAIR, which the EPA appealed. In December 2008, the Court of Appeals reinstated CAIR and directed the EPA to address the deficiencies noted in its previous ruling to vacate CAIR. In July 2011, the EPA issued a final CAIR replacement rule known as the Cross State Air Pollution Rule (CSAPR). The new rule was to become effective January 1, 2012; however, on December 30, 2011, the D.C. Circuit Court (Court) issued a decision that stayed the rule pending the Court s resolution of the petitions for review. The Court directed the EPA to implement CAIR during the stay period. In January 2012, a briefing and oral argument schedule was set. All briefing by the parties is to be completed by March 16, 2012, and the oral argument is set for April 13, 2012. In comparison to the CAIR rule, CSAPR, in the version that was stayed, significantly reduced the emission allowances allocated to our subsidiaries existing units for sulfur dioxide and nitrogen oxide in 2012, with a further reduction in 2014.

CSAPR also established new sulfur dioxide and nitrogen oxide emission allowances and did not allow carryover of the existing nitrogen oxide emission allowances allocated to WPS under CAIR. WPS did not acquire any CAIR nitrogen oxide emission allowances for 2011 and beyond other than those directly allocated to it, which were free. Sulfur dioxide emission allowances allocated under the Acid Rain Program will continue to be issued and surrendered independent of the stayed CSAPR emission allowance program. Thus, we do not expect any material impact on our financial statements as a result of being unable to carry over existing emission allowances.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule are considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they are in compliance with CAIR. Although particulate emissions also contribute to visibility impairment, the WDNR s modeling has shown the impairment to be so insignificant that additional capital expenditures on controls are not warranted. The EPA has proposed that units in compliance with CSAPR, if the stay is lifted and CSAPR is reinstated, will also be considered in compliance with

BART.

The Court may uphold CSAPR, invalidate CSAPR, or direct the EPA to make changes to CSAPR. In order to be in compliance with the stayed version of CSAPR, additional sulfur dioxide and nitrogen oxide controls would need to be installed, emission allowances would need to be purchased, and/or our subsidiaries would have to make other changes to how they operate their existing units. The installation of any necessary controls will be scheduled as part of WPS s long-term maintenance plan for its existing units; however, WPS does not currently believe it could meet the stayed CSAPR s sulfur dioxide and nitrogen oxide emission limits without purchasing additional emission allowances or by changing how its existing units are operated. Due to the uncertainty surrounding the rule, we are currently unable to predict whether, or if, additional emission allowances would be available to purchase or how much it would cost to comply. We are also currently unable to predict whether CSAPR, or any future version of CSAPR, will cause WPS to idle or abandon certain units or impact the estimated useful lives of certain units. WPS expects to recover any such future compliance costs in future rates. The impact on Integrys Energy Services is not expected to be material.

Manufactured Gas Plant Remediation

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

Table of Contents

Our natural gas utilities are responsible for the environmental remediation of 54 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA s program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. As of December 31, 2011, we estimated and accrued for $613.7 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, 2011, cash expenditures for environmental remediation not yet recovered in rates were $12.2 million. We recorded a regulatory asset of $625.9 million at December 31, 2011, which is net of insurance recoveries received of $59.9 million, related to the expected recovery of both cash expenditures and estimated future expenditures through rates.

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

NOTE 17 GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed At December 31, 2011	Expiration Less Than 1 Year	Expiration 1 to 3 Years	Expiration Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	**$ 614.2**	$ 387.6	$ 4.9	$ 221.7
Standby letters of credit (2)	**64.0**	33.4	30.6	
Surety bonds (3)	**13.5**	13.5		
Other guarantees (4)	**42.8**		20.0	22.8
Total guarantees	**$ 734.5**	$ 434.5	$ 55.5	$ 244.5

(1) Consists of our guarantees of $431.8 million to support the business operations of Integrys Energy Services; $119.1 million and $56.3 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 $61.5 million issued to support Integrys Energy Services operations and $2.5 million related to letters of credit issued to support UPPCO, WPS, MGU, NSG, MERC, PGL, and Pinnacle operations. These amounts are not reflected on our Balance Sheets.

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

(4) Consists of (a) $20.0 million related to the sale agreement for Integrys Energy Services United States wholesale electric marketing and trading business, which included a number of customary representations, warranties, and indemnification provisions. In addition, for a two-year period, counterparty payment default risk was retained with approximately 50% of the counterparties associated with the commodity contracts transferred in this transaction; (b) $10.0 million related to the sale agreement for Integrys Energy Services Texas retail marketing business, which included a number of customary representations, warranties, and indemnification provisions. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the tax law; (c) $5.0 million related to an environmental indemnification provided by Integrys Energy Services as part of the sale of the Stoneman generation facility, under which we expect that the likelihood of required performance is remote (this amount is not reflected on the Balance Sheets); and (d) $7.8 million related to other indemnifications primarily for workers compensation self insurance programs . This amount is not reflected on our Balance Sheets.

We have provided total guarantees of $532.0 million on behalf of Integrys Energy Services as shown in the table below. Our exposure under these guarantees related to open transactions at December 31, 2011, was approximately $311.1 million.

(Millions)	**December 31, 2011**	
Guarantees supporting commodity transactions	**$**	**431.8**
Standby letters of credit		**61.5**
Surety bonds		**3.2**
Other		**35.5**
Total guarantees	**$**	**532.0**

Table of Contents

NOTE 18 EMPLOYEE BENEFIT PLANS

Defined Benefit Plans

We and our subsidiaries maintain one non-contributory, 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 2011 and 2010:

(Millions)	Pension Benefits 2011	Pension Benefits 2010	Other Benefits 2011	Other Benefits 2010
Change in benefit obligation				
Obligation at January 1	**$ 1,418.5**	$ 1,337.4	**$ 538.5**	$ 475.5
Service cost	**41.4**	40.1	**19.0**	16.3
Interest cost	**80.1**	80.0	**29.5**	27.5
Plan amendments			**(0.8)**	
Actuarial loss, net	**111.7**	98.4	**9.2**	41.1
Participant contributions			**10.6**	10.7
Benefit payments	**(88.6)**	(137.4)	**(31.8)**	(34.9)
Federal subsidy on benefits paid			**2.6**	2.3
Obligation at December 31	**$ 1,563.1**	$ 1,418.5	**$ 576.8**	$ 538.5
Change in fair value of plan assets				
Fair value of plan assets at January 1	**$ 1,081.3**	$ 933.6	**$ 266.2**	$ 230.8
Actual return on plan assets	**16.5**	119.1	**(1.0)**	23.8
Employer contributions	**90.3**	166.0	**41.2**	35.8
Participant contributions			**10.6**	10.7
Benefit payments	**(88.6)**	(137.4)	**(31.5)***	(34.9)
Fair value of plan assets at December 31	**$ 1,099.5**	$ 1,081.3	**$ 285.5**	$ 266.2
Funded Status at December 31	**$ (463.6)**	$ (337.2)	**$ (291.3)**	$ (272.3)

* 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:

(Millions)	Pension Benefits 2011	2010	Other Benefits 2011	2010
Current liabilities	**$ 5.3**	$ 5.8	**$ 0.3**	$ 0.3
Noncurrent liabilities	**458.3**	331.4	**291.0**	272.0
Total liabilities	**$ 463.6**	$ 337.2	**$ 291.3**	$ 272.3

The accumulated benefit obligation for all defined benefit pension plans was $1.4 billion and $1.2 billion at December 31, 2011, and 2010, respectively. Information for pension plans with an accumulated benefit obligation in excess of plan assets is presented in the following table:

(Millions)	December 31 2011	2010
Projected benefit obligation	**$ 1,563.1**	$ 1,418.5
Accumulated benefit obligation	**1,388.0**	1,225.9
Fair value of plan assets	**1,099.5**	1,081.3

Table of Contents

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)	**2011**	**2010**	**2011**	**2010**
Accumulated other comprehensive loss (pre-tax) (1)				
Net actuarial loss	**$ 51.5**	$ 38.8	**$ 1.0**	$ 2.0
Prior service costs (credits)	**0.4**	0.7	**(1.0)**	(1.4)
Total	**$ 51.9**	$ 39.5	**$**	$ 0.6
Net regulatory assets (2)				
Net actuarial loss	**$ 593.8**	$ 429.3	**$ 127.4**	$ 98.6
Prior service costs (credits)	**11.0**	16.1	**(17.3)**	(20.0)
Transition obligation			**0.3**	0.5
Total	**$ 604.8**	$ 445.4	**$ 110.4**	$ 79.1

(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.

We recorded the PELLC pension assets acquired and liabilities assumed at fair value at the February 2007 acquisition date. Effective with the 2010 rate order, PGL and NSG reflect pension and other postretirement benefit costs in rates using our accounting basis, which was established at the time of the February 2007 PELLC merger. As a result, the merger related regulatory adjustment was eliminated. Pursuant to the 2010 rate order, a new regulatory asset was established for the remaining cumulative difference that existed between our accounting basis and the accounting basis of PGL and NSG in the pension and other postretirement benefit obligations. This regulatory asset, comprised of unrecognized benefit costs that existed prior to the PELLC merger, is not included in the amounts in the table above. Also, the amortization of this regulatory asset over the average remaining service lives of the participating employees is not included as a component of net periodic benefit cost.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2012:

(Millions)	**Pension Benefits**	**Other Benefits**
Net actuarial losses	**$ 33.1**	**$ 6.5**
Prior service costs (credits)	**5.0**	**(3.4)**
Transition obligation		**0.3**
Total 2012 estimated amortization	**$ 38.1**	**$ 3.4**

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)	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
Net periodic benefit cost						

Service cost	**$**	**41.4**	$	40.1	$	38.9	**$**	**19.0**	$	16.3	$	14.3
Interest cost		**80.1**		80.0		80.9		**29.5**		27.5		26.5
Expected return on plan assets		**(100.0)**		(92.3)		(92.5)		**(21.4)**		(19.0)		(17.7)
Amortization of transition obligation								**0.3**		0.3		0.3
Amortization of prior service cost (credit)		**5.3**		5.3		5.0		**(3.9)**		(3.8)		(3.8)
Amortization of net actuarial loss (gain)		**18.1**		8.1		1.9		**4.0**		1.9		(1.5)
Amortization of merger related regulatory adjustment						20.0						3.3
Regulatory deferral *				4.5		(4.5)				(1.3)		1.3
Net periodic benefit cost	**$**	**44.9**	$	45.7	$	49.7	**$**	**27.5**	$	21.9	$	22.7

* 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.

Table of Contents

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	
	2011	**2010**	**2011**	**2010**
Discount rate	**5.10%**	5.80%	**4.94%**	5.66%
Rate of compensation increase	**4.26%**	4.26%	**N/A**	N/A
Assumed medical cost trend rate (under age 65)	**N/A**	N/A	**7.00%**	7.50%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2016**	2016
Assumed medical cost trend rate (over age 65)	**N/A**	N/A	**7.50%**	8.00%
Ultimate trend rate	**N/A**	N/A	**5.50%**	5.50%
Year ultimate trend rate is reached	**N/A**	N/A	**2016**	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		
	2011	**2010**	**2009**
Discount rate	**5.80%**	6.15%	6.45%
Expected return on assets	**8.25%**	8.50%	8.50%
Rate of compensation increase	**4.26%**	4.26%	4.26%

	Other Benefits		
	2011	**2010**	**2009**
Discount rate	**5.66%**	5.95%	6.48%
Expected return on assets	**8.25%**	8.50%	8.50%
Assumed medical cost trend rate (under age 65)	**7.50%**	8.00%	9.00%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2016**	2013	2013
Assumed medical cost trend rate (over age 65)	**8.00%**	8.50%	9.50%
Ultimate trend rate	**5.50%**	5.50%	5.50%
Year ultimate trend rate is reached	**2016**	2013	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.

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, 2011, 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	**$ 7.2**	**$ (5.9)**
Effect on the health care component of the accumulated postretirement benefit obligation	**73.7**	**(60.9)**

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

Table of Contents

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 value of our investments by asset class:

	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.

	December 31, 2010							
	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	$ 3.4	$ 34.0	$	$ 37.4	$	$ 9.8	$	$ 9.8

Equity securities:								
United States equity	125.3	299.1		424.4	28.3	73.8		102.1
International equity	75.9	247.6		323.5	14.6	48.7		63.3
Fixed income securities:								
United States government		73.1		73.1	9.4	33.9		43.3
Foreign government		13.1	7.8	20.9				
Corporate debt		143.2	2.0	145.2		21.9		21.9
Asset-backed securities		52.8	0.2	53.0		0.4		0.4
Other		5.1		5.1	3.0			3.0
Real estate securities			30.0	30.0				
	204.6	868.0	40.0	$ 1,112.6	55.3	188.5		243.8
401(h) other benefit plan assets invested as pension assets (1)	(4.3)	(18.2)	(0.8)	(23.3)	4.3	18.2	0.8	23.3
Total (2)	$ 200.3	$ 849.8	$ 39.2	$ 1,089.3	$ 59.6	$ 206.7	$ 0.8	$ 267.1

(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.

Table of Contents

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	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 gains (losses) related to assets still held at the end of the period	**$ (0.2)**	**$ (0.1)**	**$**	**$**	**$ (0.3)**

(Millions)	Foreign Government Debt	Corporate Debt	Asset-Backed Securities	Other Fixed Income Securities	Real Estate Securities	Total
Beginning balance at December 31, 2009	$ 0.4	$ 2.9	$	$ 1.1	$ 24.9	$ 29.3
Net realized and unrealized gains (losses)	(0.2)	0.3		(0.1)	3.8	3.8
Purchases, sales, and settlements	7.6	(1.2)	0.2	(1.0)	1.3	6.9
Ending balance at December 31, 2010	$ 7.8	$ 2.0	$ 0.2	$	$ 30.0	$ 40.0
Net unrealized gains (losses) related to assets still held at the end of the period	$ (0.2)	$ 0.3	$	$	$ 3.8	$ 3.9

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 $175.3 million to pension plans and $114.2 million to other postretirement benefit plans in 2012, dependent upon 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
2012	$ 118.8	$ 29.0	$ (2.2)
2013	125.7	30.9	(2.3)
2014	117.0	32.6	(2.5)
2015	117.6	34.9	(2.6)
2016	120.8	37.4	(2.8)
2017 through 2021	657.9	224.9	(16.0)

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. In addition, certain MERC and MGU employees receive a discretionary contribution to their 401(k) Savings Plan account, regardless of their participation in the plan. The ESOP held 3.4 million shares of our common stock (market value of $186.2 million) at December 31, 2011. 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 $17.0 million in 2011, $16.9 million in 2010, and $16.8 million in 2009.

We maintain deferred compensation plans that enable certain key employees and non-employee directors to defer payment of a portion of their compensation or fees on a pre-tax basis. Non-employee directors can defer up to 100% of their director fees. Compensation is generally deferred

Table of Contents

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 $24.1 million at December 31, 2011, and $26.3 million at December 31, 2010.

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 $39.1 million at December 31, 2011, and $36.2 million at December 31, 2010. The costs incurred under this arrangement were $2.1 million in 2011, $3.5 million in 2010, and $4.0 million in 2009.

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 $17.1 million at December 31, 2011, and $18.5 million at December 31, 2010.

NOTE 19 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 were as follows at December 31:

(Millions, except share amounts)	**2011**		**2010**	
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.

Table of Contents

NOTE 20 COMMON EQUITY

We had the following changes to issued common stock during 2011, 2010 and 2009:

	Common stock shares
Balance at December 31, 2008	76,430,037
Restricted stock shares cancelled	(11,194)
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**

During 2009, and from January 1, 2010 to February 10, 2010, shares were purchased on the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of these plans. These stock issuances increased equity $22.2 million in 2011. Beginning May 1, 2011, shares were again purchased on the open market to meet the requirements of these plans.

The following table reconciles common shares issued and outstanding:

	2011		2010	
	Shares	Average Cost	Shares	Average Cost
Common stock issued	**78,287,906**		77,781,685	
Less:				
Deferred compensation rabbi trust	**382,971**	**$ 44.54**(1)	425,273	$ 43.55(1)
Restricted stock			6,333	$ 58.65(2)
Total common shares outstanding	**77,904,935**		77,350,079	

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

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

Table of Contents

Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) 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 stock plans. Diluted earnings (loss) 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, and restricted stock. The calculation of diluted earnings per share for 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 effects of an insignificant number of in-the-money securities were not included in the computation for 2009, because there was a net loss during the period, which would have caused the impact to be anti-dilutive. The calculation for 2009 also excluded 2.7 million out-of-the-money stock options that had an anti-dilutive effect. The following table reconciles our computation of basic and diluted earnings (loss) per share:

(Millions, except per share amounts)		**2011**		**2010**		**2009**
Numerator:						
Net income (loss) from continuing operations	**$**	**230.9**	$	223.5	$	(70.3)
Discontinued operations, net of tax		**(0.4)**		0.2		2.8
Preferred stock dividends of subsidiary		**(3.1)**		(3.1)		(3.1)
Noncontrolling interest in subsidiaries				0.3		1.0
Net income (loss) attributed to common shareholders	**$**	**227.4**	$	220.9	$	(69.6)
Denominator:						
Average shares of common stock basic		**78.6**		77.5		76.8
Effect of dilutive securities						
Stock-based compensation		**0.5**		0.5		
Average shares of common stock diluted		**79.1**		78.0		76.8
Earnings (loss) per common share						
Basic	**$**	**2.89**	$	2.85	$	(0.91)
Diluted		**2.87**		2.83		(0.91)

Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss, net of tax, at December 31, 2011, and 2010, were:

(Millions)		**2011**		**2010**
Cash flow hedges (1)	**$**	**(11.5)**	$	(20.4)
Unrecognized pension and other postretirement benefit costs (2)		**(31.0)**		(24.3)
Total accumulated other comprehensive loss	**$**	**(42.5)**	$	(44.7)

(1) Includes tax benefits of $9.1 million and $13.9 million at December 31, 2011, and 2010, respectively.

(2) Includes tax benefits of $20.9 million and $15.8 million at December 31, 2011, and 2010, 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 normal dividends on its common stock of no more than 103% of the previous year s common stock dividend. In addition, the PSCW currently requires WPS to maintain a calendar year average financial common equity ratio of 50.24% or higher. WPS must obtain PSCW approval if the payment of dividends would cause it to fall below this authorized level of common equity. Our right to receive dividends on the common stock of WPS is also subject to the prior rights of WPS s preferred shareholders and to provisions in WPS s restated articles of incorporation, which limit the amount of common stock dividends that WPS may pay if its common stock and common stock surplus accounts constitute less than 25% of its total capitalization.

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

Table of Contents

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

As of December 31, 2011, total restricted net assets were approximately $1,399.1 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was approximately $108.8 million at December 31, 2011.

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

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

Capital Transactions with Subsidiaries

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

Subsidiary	**Dividends to parent**	**Return of capital to parent**	**Equity contributions from parent**
WPS	**$ 102.5**	**$ 89.3**	**$ 20.0**
WPS Investments, LLC (1)	**64.5**		**8.5**
PGL (2)	**50.6**		
NSG (2)	**9.4**		
TEGE	**304.0**	**41.0**	**2.7**
MERC		**30.0**	**16.6**
IBS		**37.5**	**13.4**
MGU		**20.5**	
UPPCO		**11.5**	**2.0**
ITF (2)			**50.0**
Total	**$ 531.0**	**$ 229.8**	**$ 113.2**

(1) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At December 31, 2011, WPS and UPPCO had a 12.27% and 2.61% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2011, all equity contributions to WPS Investments, LLC were made solely by us.

(2) PGL, NSG, and ITF 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 21 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, 2011, stock options, performance stock rights, and restricted share units were outstanding under the various plans.

Table of Contents

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)	2011	2010	2009
Stock options	**$ 1.8**	$ 2.3	$ 2.0
Performance stock rights	**3.5**	10.0	4.6
Restricted shares and restricted share units	**6.1**	10.1	4.9
Total stock-based compensation expense	**$ 11.4**	$ 22.4	$ 11.5
Income tax benefit	**$ 4.6**	$ 9.0	$ 4.6

The total compensation cost capitalized for all awards during 2011, 2010, and 2009 was not significant.

Stock Options

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 options for more than 1,000,000 shares during any calendar year. No stock options will have a term 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.

The fair values of stock option awards granted were estimated using a binomial lattice model. The expected term of option awards is calculated based on historical exercise behavior and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. Our expected stock price volatility was estimated using its 10-year historical volatility. The following table shows the weighted-average fair values per stock option along with the assumptions incorporated into the valuation models:

	2011 Grant	2010 Grant	2009 Grant
Weighted-average fair value per option	**$6.57**	$5.30	$3.83
Expected term	**5 years**	6 years	8 - 9 years
Risk-free interest rate	**0.27% - 3.90%**	2.38%	2.50% - 2.78%
Expected dividend yield	**5.34%**	5.46%	5.50%
Expected volatility	**25%**	25%	19%

A summary of stock option activity for 2011, and information related to outstanding and exercisable stock options at December 31, 2011, is presented below:

	Stock Options	Weighted-Average Exercise Price Per	Weighted-Average Remaining Contractual	Aggregate Intrinsic Value

		Share		Life (in Years)		(Millions)
Outstanding at December 31, 2010	2,992,699	$	47.59			
Granted	**241,207**		**49.40**			
Exercised	**(241,302)**		**42.72**			
Expired	**(38,974)**		**50.58**			
Outstanding at December 31, 2011	**2,953,630**	**$**	**48.09**	**5.73**	**$**	**19.0**
Exercisable at December 31, 2011	**1,991,120**	**$**	**49.74**	**4.72**	**$**	**9.8**

As of December 31, 2011, $1.2 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.5 years.

Cash received from option exercises was $2.3 million during 2011. Cash received from option exercises during 2010 was $18.8 million and was not significant during 2009. The actual tax benefit realized for the tax deductions from these option exercises was not significant in 2011, 2010, and 2009.

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, 2011. This is calculated as the difference between our closing stock price on December 31, 2011, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during 2011 and 2010 was $2.8 million and $4.9 million, respectively, and was not significant during 2009.

Table of Contents

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 either paid out in shares of our common stock, or an eligible employee 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 now 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:

	2011	**2010**	**2009**
Risk-free interest rate	**0.00% - 1.27%**	0.21% - 0.56%	1.38% - 4.71%
Expected dividend yield	**5.28% - 5.34%**	5.34%	4.50% - 5.50%
Expected volatility	**21% - 36%**	20% - 34%	15% - 26%

A summary of the 2011 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, 2010		$
Granted	**16,959**	**49.21**
Award modifications	**118,989**	**45.75**

Outstanding at December 31, 2011	**135,948**	**$**	**46.18**

---

* 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 2011 activity related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2010	341,638
Granted	**67,790**
Award modifications	**(118,989)**
Distributed	**(129,237)**
Adjustment for final payout	**25,013**
Outstanding at December 31, 2011	**186,215**

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of December 31, 2011, was $56.77 per performance stock right.

Table of Contents

As of December 31, 2011, $2.1 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.5 years.

The total intrinsic value of performance stock rights distributed during the years ended December 31, 2011 and 2010, was $6.3 million and $1.9 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during the years ended December 31, 2011 was $2.5 million and was not significant in 2010. No performance stock rights were distributed in 2009 because the performance percentage was below the threshold payout level for those rights that were vested and eligible to be distributed during the year ended December 31, 2009.

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. During the vesting period, restricted share recipients had voting rights and were entitled to dividends in the same manner as other common shareholders. Restricted share unit recipients do not have voting rights, but they receive dividend equivalents in the form of additional restricted share units. During 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at December 31, 2011.

Restricted shares and 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 now 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 and restricted share unit awards (equity and liability awards) for the year ended December 31, 2011, is presented below:

	Restricted Share and Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2010	455,933	$ 43.36
Granted	**179,584**	**49.39**
Dividend equivalents	**25,414**	**44.22**
Vested	**(151,505)**	**44.46**
Forfeited	**(11,704)**	**44.90**
Outstanding at December 31, 2011	**497,722**	**$ 45.21**

As of December 31, 2011, $9.5 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.5 years.

The total intrinsic value of restricted share and restricted share unit awards vested for the years ended December 31, 2011, 2010, and 2009 was $7.5 million, $4.9 million, and $2.7 million, respectively. The actual tax benefit realized for the tax deductions from the vesting of restricted shares and restricted share units during the years ended December 31, 2011, 2010, and 2009 was $3.0 million, $2.0 million, and $1.1 million, respectively.

The weighted-average grant date fair value of restricted shares and restricted share units awarded during the years ended December 31, 2011, 2010, and 2009 was $49.39, $41.67, and $42.12 per share, respectively.

NOTE 22 VARIABLE INTEREST ENTITIES

In 2011, our subsidiary 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 of 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, 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 in our balance sheet were not significant.

Table of Contents

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these purchased power agreements reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under the agreement. This contract expires in 2014. The other agreement contains a tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. This contract expires in 2016. As of December 31, 2011, and December 31, 2010, we had approximately 517.5 megawatts of capacity available under these agreements. We evaluated each 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, 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.

Table of Contents

NOTE 23 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, 2011			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	**$ 0.1**	**$ 9.1**	**$**	**$ 9.2**
Financial transmission rights (FTRs)			**2.3**	**2.3**
Petroleum product contracts	**0.1**			**0.1**
Nonregulated Segments				
Natural gas contracts	**50.7**	**104.1**	**8.7**	**163.5**
Electric contracts	**41.2**	**71.2**	**3.9**	**116.3**
Foreign exchange contracts		**0.2**		**0.2**
Total Risk Management Assets	**$ 92.1**	**$ 184.6**	**$ 14.9**	**$ 291.6**
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	**$ 5.5**	**$ 39.2**	**$**	**$ 44.7**
FTRs			**0.1**	**0.1**
Coal contract			**6.9**	**6.9**
Nonregulated Segments				
Natural gas contracts	**55.0**	**105.6**	**0.4**	**161.0**
Electric contracts	**54.2**	**131.1**	**15.4**	**200.7**
Foreign exchange contracts	**0.2**			**0.2**
Total Risk Management Liabilities	**$ 114.9**	**$ 275.9**	**$ 22.8**	**$ 413.6**

	December 31, 2010			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ 0.6	$ 3.2	$	$ 3.8
FTRs			3.1	3.1
Petroleum product contracts	0.6			0.6
Coal contract			3.7	3.7
Nonregulated Segments				
Natural gas contracts	60.7	100.7	34.6	196.0
Electric contracts	29.5	69.8	17.4	116.7
Interest rate swaps		0.9		0.9
Foreign exchange contracts	0.1	1.4		1.5
Total Risk Management Assets	$ 91.5	$ 176.0	$ 58.8	$ 326.3
Risk Management Liabilities				
Utility Segments				

Natural gas contracts	$	3.7	$	22.3	$		$	26.0
FTRs						0.2		0.2
Coal contract						1.2		1.2
Nonregulated Segments								
Natural gas contracts		66.8		110.4		4.4		181.6
Electric contracts		45.0		101.5		32.3		178.8
Foreign exchange contracts		1.4		0.1				1.5
Total Risk Management Liabilities	$	116.9	$	234.3	$	38.1	$	389.3
Long-term debt hedged by fair value hedge	$		$	50.9	$		$	50.9

The risk management assets and liabilities listed in the tables include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. For more information on derivative instruments, see Note 2, *Risk Management Activities*.

Table of Contents

The following tables show net risk management assets (liabilities) transferred between the levels of the fair value hierarchy during 2011:

	Nonregulated Segments			Natural Gas Contracts		
	December 31, 2011			December 31, 2010		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$ 0.1	$
Transfers into Level 2 from	**$**	**N/A**	**24.4**	$	N/A	0.8
Transfers into Level 3 from		**0.6**	**N/A**		1.7	N/A

	Nonregulated Segments			Electric Contracts		
	December 31, 2011			December 31, 2010		
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Level 1**	**Level 2**	**Level 3**
Transfers into Level 1 from	**N/A**	**$**	**$ (1.8)**	N/A	$ (10.1)	$ (18.0)
Transfers into Level 2 from	**$ 3.4**	**N/A**	**(18.4)**	$ (0.2)	N/A	2.6
Transfers into Level 3 from	**0.7**	**(6.6)**	**N/A**		(4.9)	N/A

Derivatives are transferred between the levels of the fair value hierarchy primarily due to changes in the source of data used to construct price curves as a result of changes in market liquidity.

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

2010	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) gains recorded as regulatory assets or liabilities			**(1.7)**	**(8.0)**	**(9.7)**
Net unrealized losses 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**

2010	Nonregulated Segments		Utility Segments		
(Millions)	**Natural Gas**	**Electric**	**FTRs**	**Coal Contract**	**Total**
	$ 31.4	$ 86.5	$ 3.5	$	$ 121.4

Balance at the beginning of the period					
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)

Table of Contents

2009

(Millions)		Total
Balance at the beginning of period	$	182.0
Net realized and unrealized gain included in earnings		32.0
Net unrealized gain recorded as regulatory assets or liabilities		2.2
Net unrealized gain included in other comprehensive loss		16.3
Net purchases and settlements		(36.0)
Net transfers in/out of Level 3		(75.1)
Balance at the end of the period	$	121.4
Net unrealized gain included in earnings related to instruments still held at the end of the period	$	35.4

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:

	2011		2010	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	**$ 2,122.0**	**$ 2,281.5**	$ 2,638.5	$ 2,687.8
Preferred stock of subsidiary	**51.1**	**51.8**	51.1	46.8

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity, without considering the effect of third-party credit enhancements. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model.

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 24 ADVERTISING COSTS

In 2011, costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment. Net capitalized direct-response advertising costs totaled $3.4 million as of December 31, 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 $1.5 million for the year ended December 31, 2011.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising. Other advertising expense was $7.4 million, $7.8 million, and $4.8 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Table of Contents

NOTE 25 MISCELLANEOUS INCOME

Total miscellaneous income was as follows at December 31:

(Millions)	2011	2010	2009
Equity earnings on investments	**$ 79.4**	$ 78.3	$ 76.1
Key executive life insurance income	**2.3**	3.1	2.3
Interest and dividend income	**1.0**	3.7	5.6
Equity portion of AFUDC	**0.7**	1.6	6.0
Gain (loss) on foreign currency translation *		4.7	(0.1)
Other	**1.4**	0.1	(0.9)
Total miscellaneous income	**$ 84.8**	$ 91.5	$ 89.0

* 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 26 REGULATORY ENVIRONMENT

Wisconsin

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 rate order allows for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection. The rate order also allows for the deferral of direct Cross State Air Pollution Rule (CSAPR) compliance costs, including carrying costs. No amounts were deferred related to CSAPR as of December 31, 2011.

2011 Rates

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

The order also addressed the new Wisconsin electric fuel rule, which was finalized on March 1, 2011. The new fuel rule is effective retroactive to January 1, 2011. It requires the deferral of under or over-collections of fuel and purchased power costs that exceed a 2% price variance from the cost of fuel and purchased power included in rates. Under or over-collections deferred in the current year will be recovered or refunded in a future rate proceeding. As of December 31, 2011, $2.2 million was deferred as a regulatory liability related to 2011 fuel and purchased power cost over-collections. All 2010 fuel cost over-collections were refunded to customers in 2011.

2010 Rates

On December 22, 2009, the PSCW issued a final written order for WPS, effective January 1, 2010. It authorized an electric rate increase of $18.2 million, offset by an $18.2 million refund of 2009 and 2008 fuel cost over-collections. It also authorized a retail natural gas rate increase of $13.5 million. Based on an order issued on April 1, 2010, the remaining $10.0 million of the total 2008 and 2009 fuel cost over-collections, plus interest of $1.3 million, was refunded to customers in April and May 2010.

Table of Contents

Michigan

2012 UPPCO Rates

On December 20, 2011, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $4.2 million, effective January 1, 2012. The new rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in UPPCO s regulatory capital structure. The settlement required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011, and replace it with a new weather-normalized decoupling mechanism, beginning January 1, 2013. As a result, UPPCO has no decoupling mechanism in place for 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 (discussed below) after the close of December 2010 business, but retained the decoupling mechanism.

2010 UPPCO Rates

On December 16, 2009, the MPSC issued a final written order for UPPCO authorizing a retail electric rate increase of $6.5 million, effective January 1, 2010. The new rates reflected a 10.90% return on common equity and a common equity ratio of 54.83% in UPPCO s regulatory capital structure. The order included approval of a decoupling mechanism, as well as an uncollectibles expense tracking mechanism, both effective January 1, 2010. The uncollectibles expense tracking mechanism 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.

2010 MGU Rates

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

Illinois

2012 Rates

On January 10, 2012, the ICC issued a final order authorizing a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG, effective January 21, 2012. The rates for PGL reflect a 9.45% return on common equity and a common equity ratio of 49.00% in PGL s regulatory capital structure. The rates for NSG reflect a 9.45% return on common equity and a common equity ratio of 50.00% in NSG s regulatory capital structure. The rate order also approved a permanent decoupling mechanism. However, the appeal of the original decoupling order is pending and, depending on the outcome, could impact the current rate order provision for decoupling. On February 23, 2012, the ICC rejected the rehearing requests filed by PGL, NSG, and certain interveners. The rate order remains subject to possible appeal. The Illinois Attorney General filed a motion to stay the implementation of the permanent decoupling mechanism.

2010 Rates

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

The ICC also approved a rider mechanism for PGL to earn a return on and recover the costs, above an annual baseline, of the AMRP through a special charge on customers bills, known as Rider ICR. The AMRP is a 20-year project that began in 2011 under which PGL is replacing its cast iron and ductile iron pipes with steel and polyethylene pipes. In June 2010, the ICC issued a rehearing order approving PGL s proposed baseline of $45.28 million with an annual escalation factor. Recovery of costs for the AMRP became effective on April 1, 2011. On September 30, 2011,

Table of Contents

the Illinois Appellate Court, First District, reversed the ICC s approval of Rider ICR, concluding it was improper single issue ratemaking. All other issues on appeal were affirmed by the Illinois Appellate Court. PGL and the ICC filed for leave to appeal with the Illinois Supreme Court, but their requests were denied. The Illinois Appellate Court will now remand the matter to the ICC for further proceeding consistent with its September 30, 2011 decision. As a result, PGL may be obligated to refund some amounts previously collected from customers under Rider ICR.

2009 Illinois Legislation

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

Minnesota

2011 Rates

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

2010 Rates

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

Federal

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

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

As of December 31, 2011, Integrys Energy Services expected to receive future refunds of $3.8 million. Once the orders on compliance filings are issued, refunds will be made. Any refunds will include interest for the period from payment to refund.

NOTE 27 SEGMENTS OF BUSINESS

At December 31, 2011, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of WPS, MGU, MERC, PGL, and NSG.
- The electric utility segment includes the regulated electric utility operations of WPS and UPPCO.

Table of Contents

• The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Wisconsin, Michigan, Minnesota, and Illinois.

• Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas to commercial, industrial, and residential customers in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.

• The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at WPS, MGU, MERC, UPPCO, PGL, NSG, and IBS. 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			
2011 (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	**$ 1,987.2**	**$ 1,307.3**	**$**	**$ 3,294.5**	**$ 1,394.8**	**$ 19.4**	**$**	**$ 4,708.7**
Intersegment revenues	**10.8**			**10.8**	**1.1**	**1.5**	**(13.4)**	
Impairment losses on property, plant, and equipment					**4.6**			**4.6**
Restructuring expense		**0.2**		**0.2**	**1.8**			**2.0**
Depreciation and amortization expense	**126.1**	**88.5**		**214.6**	**12.7**	**23.3**	**(0.5)**	**250.1**
Miscellaneous income	**2.2**	**0.8**	**79.1**	**82.1**	**0.4**	**19.3**	**(17.0)**	**84.8**
Interest expense	**48.4**	**41.8**		**90.2**	**2.3**	**53.3**	**(17.0)**	**128.8**
Provision (benefit) for income taxes	**61.2**	**59.2**	**31.3**	**151.7**	**(7.1)**	**(10.7)**		**133.9**
Net income (loss) from continuing operations	**103.9**	**103.0**	**47.8**	**254.7**	**(6.2)**	**(17.6)**		**230.9**
Discontinued operations					**0.1**	**(0.5)**		**(0.4)**
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**	**18.0**	**10.0**		**311.4**

Table of Contents

2010 (Millions)	Regulated Operations: Natural Gas Utility	Regulated Operations: Electric Utility	Regulated Operations: Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations: Integrys Energy Services	Nonutility and Nonregulated Operations: Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$ 2,056.4	$ 1,312.1	$	$ 3,368.5	$ 1,822.5	$ 12.2	$	$ 5,203.2
Intersegment revenues	0.8	26.8		27.6	1.2		(28.8)	
Impairment losses on property, plant, and equipment					43.2			43.2
Net loss on Integrys Energy Services dispositions related to strategy change					14.1			14.1
Restructuring expense	(0.2)	(0.3)		(0.5)	8.3	0.1		7.9
Depreciation and amortization expense	130.9	94.7		225.6	17.2	23.0		265.8
Miscellaneous income	1.6	1.5	77.6	80.7	9.1	41.9	(40.2)	91.5
Interest expense	49.7	43.9		93.6	6.7	87.8	(40.2)	147.9
Provision (benefit) for income taxes	65.3	63.1	31.4	159.8	3.6	(15.2)		148.2
Net income (loss) from continuing operations	84.6	112.3	46.2	243.1	2.8	(22.4)		223.5
Discontinued operations					0.2			0.2
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	15.2	22.8		258.8

Table of Contents

2009 (Millions)	Regulated Operations: Natural Gas Utility	Regulated Operations: Electric Utility	Regulated Operations: Electric Transmission Investment	Total Regulated operations	Nonutility and Nonregulated Operations: Integrys Energy Services	Nonutility and Nonregulated Operations: Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$ 2,236.9	$ 1,258.9	$	$ 3,495.8	$ 3,992.5	$ 11.5	$	$ 7,499.8
Intersegment revenues	0.6	42.7		43.3	1.5		(44.8)	
Impairment losses on property, plant, and equipment					0.7			0.7
Net loss on Integrys Energy Services dispositions related to strategy change					28.9			28.9
Restructuring expense	6.9	8.6		15.5	27.2	0.8		43.5
Goodwill impairment loss	291.1			291.1				291.1
Depreciation and amortization expense	106.1	90.3		196.4	19.0	15.2		230.6
Miscellaneous income	3.1	4.8	75.3	83.2	6.0	46.5	(46.7)	89.0
Interest expense	52.2	41.6		93.8	13.1	104.6	(46.7)	164.8
Provision (benefit) for income taxes	7.8	51.4	29.8	89.0	19.0	(24.3)		83.7
Net income (loss) from continuing operations	(171.5)	91.4	45.5	(34.6)		(35.7)		(70.3)
Discontinued operations					2.8			2.8
Preferred stock dividends of subsidiary	(0.6)	(2.5)		(3.1)				(3.1)
Noncontrolling interest in subsidiaries					1.0			1.0
Net income (loss) attributed to common shareholders	(172.1)	88.9	45.5	(37.7)	3.8	(35.7)		(69.6)
Total assets	4,675.7	2,834.7	395.9	7,906.3	3,547.5	1,462.7	(1,071.9)	11,844.6
Cash expenditures for long-lived assets	136.9	250.4		387.3	22.4	34.5		444.2

Geographic Information (Millions)	2011 Revenues	2011 Long-Lived Assets	2010 Revenues	2010 Long-Lived Assets	2009 Revenues	2009 Long-Lived Assets
United States	**$ 4,708.7**	**$ 8,115.5**	$ 5,199.7	$ 7,677.0	$ 6,628.5	$ 7,537.0
Canada *			3.5		871.3	
Total	**$ 4,708.7**	**$ 8,115.5**	$ 5,203.2	$ 7,677.0	$ 7,499.8	$ 7,537.0

* Revenues and assets of Canadian subsidiaries. Includes the impact in 2009 of the sale of Canadian operations at Integrys Energy Services.

Table of Contents

NOTE 28 QUARTERLY FINANCIAL INFORMATION (Unaudited)

(Millions, except share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2011					
Total revenues	**$ 1,627.1**	**$ 1,010.8**	**$ 938.7**	**$ 1,132.1**	**$ 4,708.7**
Operating income	**208.7**	**67.5**	**70.8**	**61.8**	**408.8**
Net income from continuing operations	**123.4**	**30.8**	**37.6**	**39.1**	**230.9**
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	**$ 1.57**	**$ 0.38**	**$ 0.47**	**$ 0.49**	**$ 2.90**
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	**1.56**	**0.38**	**0.47**	**0.48**	**2.88**
Earnings per common share (basic)	**1.56**	**0.37**	**0.47**	**0.49**	**2.87**
2010					
Total revenues	$ 1,903.4	$ 1,014.8	$ 997.9	$ 1,287.1	$ 5,203.2
Operating income	119.4	136.2	39.2	133.3	428.1
Net income from continuing operations	50.4	79.6	21.1	72.4	223.5
Net income	50.5	79.6	21.1	72.5	223.7
Net income attributed to common shareholders	49.7	79.1	20.4	71.7	220.9
Earnings per common share (basic) *					
Net income from continuing operations	$ 0.65	$ 1.02	$ 0.26	$ 0.92	$ 2.85
Earnings per common share (basic)	0.65	1.02	0.26	0.92	2.85
Earnings per common share (diluted) *					
Net income from continuing operations	0.64	1.02	0.26	0.91	2.83
Earnings per common share (basic)	0.64	1.02	0.26	0.91	2.83

* 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.

Because of various factors, the quarterly results of operations are not necessarily comparable.

Table of Contents

H. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors and Shareholders 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, 2011 and 2010, and the related consolidated statements of income, equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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, 2012 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
February 28, 2012

Table of Contents

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 Controls

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, 2011, 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.

Table of Contents

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 10, 2012 (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 2011 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 2011 and 2010 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.

Table of Contents

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:

(2) Financial Statement Schedules.

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.

Table of Contents

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 this 28th day of February, 2012.

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 and on the dates indicated.

Signature	Title	Date
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	
James L. Kemerling *	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)	February 28, 2012
/s/ Joseph P. O Leary Joseph P. O Leary	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2012
/s/ Diane L. Ford Diane L. Ford	Vice President and Corporate Controller (principal accounting officer)	February 28, 2012
* By: /s/ Diane L. Ford Diane L. Ford	Attorney-in-Fact	February 28, 2012

Table of Contents

SCHEDULE I - CONDENSED

PARENT COMPANY FINANCIAL STATEMENTS

INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. STATEMENTS OF INCOME AND RETAINED EARNINGS

Year Ended December 31 (Millions, except per share data)		2011		2010		2009
Equity earnings (loss) in excess of dividends from subsidiaries	$	(184.9)	$	119.8	$	(157.2)
Dividends from subsidiaries		461.3		153.7		147.0
Income (loss) from subsidiaries		276.4		273.5		(10.2)
Investment income and other		24.2		29.9		25.5
Total income		300.6		303.4		15.3
Operating expense		5.9		6.3		6.3
Operating income		294.7		297.1		9.0
Interest expense		52.2		65.8		79.4
Income (loss) before taxes		242.5		231.3		(70.4)
Provision for income taxes		14.7		10.6		2.0
Net income (loss) from continuing operations		227.8		220.7		(72.4)
Discontinued operations, net of tax		(0.4)		0.2		2.8
Net income (loss) attributed to common shareholders	$	227.4	$	220.9	$	(69.6)
Retained earnings, beginning of year	$	350.8	$	337.0	$	614.7
Common stock dividends		(211.8)		(208.7)		(206.9)
Other		(2.8)		1.6		(1.2)
Retained earnings, end of year	$	363.6	$	350.8	$	337.0
Average shares of common stock						
Basic		78.6		77.5		76.8
Diluted		79.1		78.0		76.8
Earnings (loss) per common share (basic)						
Net income (loss) from continuing operations	$	2.90	$	2.85	$	(0.95)
Discontinued operations, net of tax		(0.01)				0.04
Earnings (loss) per common share (basic)	$	2.89	$	2.85	$	(0.91)
Earnings (loss) per common share (diluted)						
Net income (loss) from continuing operations	$	2.88	$	2.83	$	(0.95)
Discontinued operations, net of tax		(0.01)				0.04
Earnings (loss) per common share (diluted)	$	2.87	$	2.83	$	(0.91)
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.

Table of Contents

SCHEDULE I - CONDENSED

PARENT COMPANY FINANCIAL STATEMENTS

INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

B. BALANCE SHEETS

At December 31 (Millions)	2011	2010
Assets		
Cash and cash equivalents	$ 1.9	$ 100.6
Accounts receivable from related parties	33.0	34.1
Interest receivable from related parties	4.9	4.7
Receivable from related parties		12.9
Deferred income taxes	1.1	
Notes receivable from related parties	22.4	55.6
Other current assets	70.4	82.1
Current assets	133.7	290.0
Total investments in subsidiaries, at equity	3,687.5	4,057.8
Notes receivable from related parties	243.9	234.6
Property and equipment, net of accumulated depreciation of $1.0 and $0.9, respectively	4.9	5.0
Receivables from related parties	17.8	23.2
Deferred income taxes	30.3	26.3
Other	30.3	31.5
Total assets	$ 4,148.4	$ 4,668.4
Liabilities and Equity		
Short-term notes payable to related parties	$ 181.8	$ 487.0
Short-term debt	92.6	
Current portion of long-term notes payable to related parties		325.0
Current portion of long-term debt	100.0	
Accounts payable to related parties	1.4	1.8
Interest payable to related parties	0.1	4.7
Accounts payable	1.1	1.1
Deferred income taxes	12.8	11.9
Other current liabilities	3.6	23.0
Current liabilities	393.4	854.5
Long-term notes payable to related parties	21.0	21.0
Long-term debt	674.6	804.7
Deferred income taxes	69.9	60.9

Payables to related parties	**3.3**	3.1
Other	**24.8**	18.4
Long-term liabilities	**793.6**	908.1
Commitments and contingencies		
Total common shareholders equity	**2,961.4**	2,905.8
Total liabilities and Equity	**$ 4,148.4**	$ 4,668.4

The accompanying notes to Integrys Energy Group s parent company financial statements are an integral part of these statements.

Table of Contents

SCHEDULE I - CONDENSED

PARENT COMPANY FINANCIAL STATEMENTS

INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

C. STATEMENTS OF CASH FLOWS

Year Ended December 31 (Millions)	2011	2010	2009
Operating Activities			
Net income (loss)	$ **227.4**	$ 220.9	$ (69.6)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Discontinued operations, net of tax	**0.4**	(0.2)	(2.8)
Equity loss (income) from subsidiaries, net of dividends	**184.9**	(119.8)	157.2
Deferred income taxes	**29.2**	44.2	24.4
Gain on sale of investment			(0.4)
Other	**3.5**	21.0	23.7
Changes in working capital			
Acounts receivables	**(0.6)**	1.4	0.5
Accounts receivables from related parties	**0.9**	4.4	(4.2)
Receivable from related parties	**13.8**	(12.9)	
Other current assets	**12.8**	(54.5)	(2.4)
Accounts payable		0.4	0.5
Accounts payable to related parties	**(5.0)**	(2.0)	(44.6)
Other current liabilities	**15.9**	5.5	(7.4)
Net cash provided by operating activities	**483.2**	108.4	74.9
Investing Activities			
Short-term notes receivable from related parties	**33.3**	(2.6)	97.9
Long-term notes receivable from related parties	**(10.0)**	(15.0)	(10.0)
Receivables from related parties	**0.6**	(14.2)	1.5
Equity contributions to subsidiaries	**(63.2)**	(57.8)	(56.1)
Return of capital from subsidiaries	**229.8**	78.0	155.5
Proceeds from sale of investment		0.4	0.5
Other	**0.7**	0.7	0.5
Net cash provided (used for) by investing activities	**191.2**	(10.5)	189.8
Financing Activities			
Commercial paper, net	**92.6**	(205.1)	(47.7)
Short-term notes payable to related parties	**(305.2)**	171.3	39.6
Redemption of long-term notes payable to related parties	**(325.0)**		
Redemption of notes payable			(157.9)
Redemption of short-term debt			(50.0)
Issuance of long-term debt		250.0	155.0
Redemption of long-term debt	**(30.2)**	(65.6)	(150.0)
Issuance of common stock	**10.2**	33.2	
Dividends paid on common stock	**(206.4)**	(186.1)	(206.9)
Other	**(9.1)**	(14.0)	(18.7)
Net cash used for financing activities	**(773.1)**	(16.3)	(436.6)

Change in cash and cash equivalents		**(98.7)**	81.6	(171.9)
Cash and cash equivalents at beginning of year		**100.6**	19.0	190.9
Cash and cash equivalents at end of year	**$**	**1.9**	$ 100.6	$ 19.0

The accompanying notes to Integrys Energy Group s parent company financial statements are an integral part of these statements.

Table of Contents

SCHEDULE I - CONDENSED

PARENT COMPANY FINANCIAL STATEMENTS

INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

D. 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)	2011	2010	2009
Cash paid for interest	**$ 44.6**	$ 37.0	$ 57.3
Cash paid for interest related parties	**6.8**	20.2	23.6
Cash (received) paid for income taxes	**(46.3)**	13.6	(15.4)

Significant noncash transactions were:

(Millions)	2011	2010	2009
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.

	2011		2010	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term notes receivable from related parties	**$ 243.9**	**$ 275.6**	$ 234.6	$ 261.2
Current portion of long-term notes payable to related parties			325.0	325.7
Long-term notes payable to related parties	**21.0**	**21.0**	21.0	21.0

NOTE 3 SHORT-TERM NOTES RECEIVABLE RELATED PARTIES

(Millions)	2011	2010
UPPCO	**$ 7.7**	$ 9.0
MERC	**14.7**	14.9
MGU		8.7
IBS		23.0
Total	**$ 22.4**	$ 55.6

Table of Contents

NOTE 4 LONG-TERM NOTES RECEIVABLE RELATED PARTIES

(Millions)		2011	2010
WPS			
Series	Year Due		
8.76%	2015	**$ 3.1**	$ 3.4
7.35%	2016	**4.8**	5.2