Simply the BEST

Named America's most reliable utility

2013 Annual Report

We Energies
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News Release

We Energies named best in nation for keeping the lights on

Award recognizes most reliable electric utilities nationwide

MILWAUKEE – We Energies has received the 2013 ReliabilityOne™ national award for superior reliability of its electric system.

The national award is based on the company's performance for the year 2012 and is given annually by PA Consulting Group to utilities that have excelled in delivering the most reliable electric service to their customers.

"We're honored to be named the most reliable utility in America. This national award is a testament to the skill and professionalism of our employees who dedicate themselves to outstanding customer care every day," said Gale Klappa, chairman, president and chief executive officer of We Energies.

All utilities operating electric delivery networks in North America are eligible for the ReliabilityOne Award. The selection is based primarily on statistics that measure the frequency and duration of customer outages. After initial recipients are identified, each potential winner undergoes an on-site certification – an independent review of the processes and systems used to collect, analyze and report a company's reliability results.

At last night's ceremony in New York, We Energies also received – for the ninth time in the past 12 years – the ReliabilityOne Award for outstanding electric reliability performance in the Midwest. There are five regional awards – Northeast, Mid-Atlantic, Midwest, Plains and West.

We Energies has made significant investments in recent years to strengthen the reliability of its network by rebuilding hundreds of miles of distribution lines, and building and upgrading substations and other infrastructure. The company's forestry management also has been recognized for responsible tree trimming practices to keep branches from coming into contact with power lines.

TOTAL SHAREHOLDER RETURN

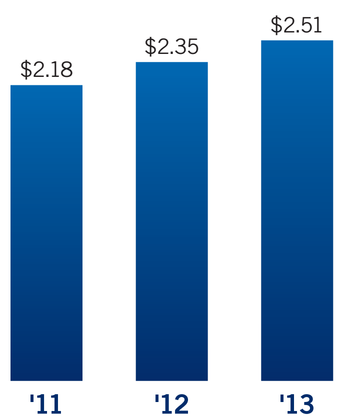
Over the past decade, our total shareholder return has outperformed the investment returns of the Dow Jones Industrials, the S&P 500, NASDAQ, and all the major utility indexes.

TEN-YEAR PERFORMANCE (2004–2013)*	
WISCONSIN ENERGY	**227.1%**
Dow Jones Utilities Average	170.5%
Philadelphia Utility Index	137.1%
S&P Electric Index	132.4%
Dow Jones Industrial Average	104.9%
S&P 500 Index	104.3%
NASDAQ Composite Index	133.2%

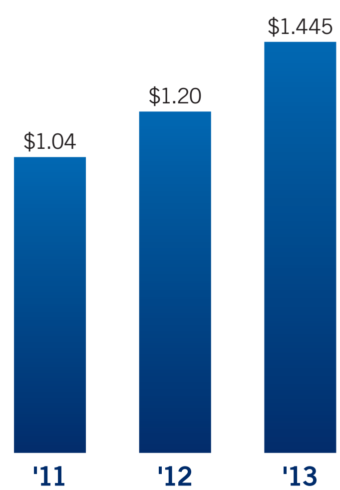
*Stock price appreciation plus reinvested dividends.

FINANCIAL HIGHLIGHTS

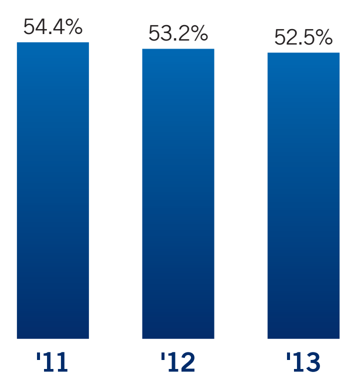
EARNINGS PER SHARE – CONTINUING OPERATIONS



DIVIDENDS PER SHARE[a]

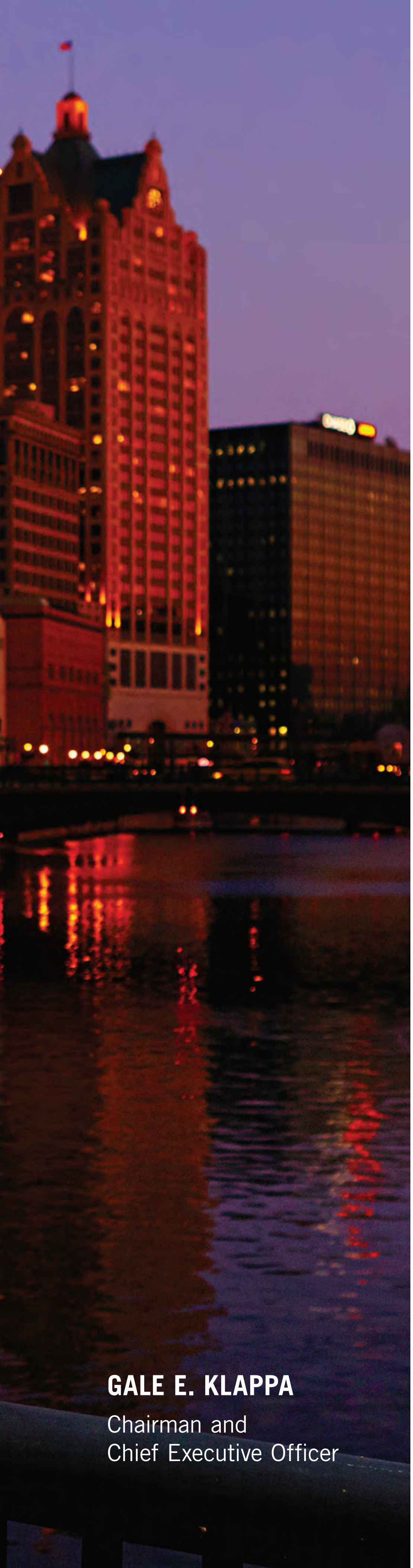


YEAR-END DEBT TO TOTAL CAPITAL[b]



a. The quarterly dividend was increased from 38.25 cents per share to 39 cents per share in the first quarter of 2014.

b. Attributes $250 million of 2007 Series A Junior Subordinated Notes to common equity. A majority of the rating agencies currently attribute at least 50% common equity to these securities. For further details, see page F-17.



GALE E. KLAPPA

Chairman and
Chief Executive Officer

TO OUR STOCKHOLDERS,

It was the early 1900s. A different time. A far different era. But as the country faced a brave new century, Theodore Roosevelt — a noteworthy figure in American history — wrote of a strongly held belief that still holds true today. Roosevelt said… "the best prize that life offers is the chance to work hard at work worth doing."

That phrase summarizes the year 2013 for Wisconsin Energy. It was a noteworthy year. A year of progress. A year of accomplishment for our customers and our stockholders. Here are the highlights.

We delivered:

- The highest net income in company history
- The highest earnings per share in company history
- The strongest balance sheet in more than 15 years

We invested nearly $700 million in our core business to maintain reliability and improve customer service.

In addition, through dividends and share buybacks, we returned more cash to shareholders than during any other year in our history.

Our stock price set 16 new all-time trading highs during 2013, rising to $45 a share on April 30.

For the full year, our total shareholder return was 16.1 percent — surpassing the performance of all the major utility indexes.

We achieved the second safest year of operation since we began keeping records more than 100 years ago. Injuries and lost-time accidents are down approximately 70 percent since 2003.

We returned more cash to shareholders than during any other year in our history.

J.D. Power and Associates ranked our company the number one large electric utility in the Midwest for customer satisfaction among business customers. And by year-end, we achieved our highest overall customer satisfaction ratings in the past decade — likely our best ever.

In northern Wisconsin, we completed a new generating unit that is being fueled with wood waste. The project was completed on time and on budget — adding diversity to our portfolio of renewable energy.

For the sixth consecutive year, Wisconsin Energy was named one of the 100 best corporate citizens in the United States by Corporate Responsibility magazine.

And as you saw on the cover of this report, we were honored to be named the most reliable utility in America by an independent firm that analyzes data from electric delivery networks across America on customer outages, restoration times, and service quality.

I'm proud of the thousands of men and women across our company whose skill, dedication, and passion for customer satisfaction made this recognition possible. The national award builds on a long track record of exceptional performance. Nine times in the past 12 years, we've also been named the best in the Midwest for keeping the lights on.

We were honored to be named the most reliable utility in America.

So where do we go from here? The answer is that we still have much work to do. Financially, one of our goals is to implement a dividend policy that calls for us to pay out 65 to 70 percent of our earnings in dividends in 2017 — a level that will be more competitive with our peers across the regulated utility sector. Toward that end, our board voted in January to raise the quarterly dividend on the company's common stock to 39 cents a share. The new annual rate is now \$1.56 a share. This represents a 30-percent increase over the dividend rate that was in effect at the end of 2012.

The board has also approved a new share repurchase plan. The new plan authorizes management to purchase up to \$300 million of Wisconsin Energy common stock from 2014 through 2017.

Operationally, our goal is to maintain our status as one of the nation's most reliable utilities.

We'll be placing a greater focus on pipes, poles, wires, transformers, and substations — the building blocks of our delivery business.

Our capital budget calls for investing \$3.2 billion to \$3.5 billion over the period 2014 through 2018. In this five-year plan, we've moved from the large, high-profile projects that were part of our Power the Future effort, to many smaller-scale projects designed to upgrade our aging distribution infrastructure.

We'll be placing a greater focus on pipes, poles, wires, transformers, and substations — the building blocks of our delivery business. We're rebuilding 2,000 miles of electric distribution lines that are more than 50 years old and replacing 18,500 power poles, 20,000 transformers, and literally hundreds of substation components.

On the natural gas side of our business, we're replacing 1,100 miles of gas mains, 83,000 individual gas distribution lines, and approximately 233,000 meter sets.

One of the larger projects being planned by our natural gas group is a new line that would expand our delivery network in west central Wisconsin. This 85-mile line would run between Eau Claire County, in the far western part of the state, and the city of Tomah in Monroe County. The project is designed to address reliability concerns in western Wisconsin and meet growing demand. Demand is being driven by customers converting from propane to natural gas — and by the growth of the sand mining industry in the region.

Ten communities along the proposed route have now passed resolutions authorizing us to begin operating natural gas distribution systems within their borders.

If we receive timely approval from the Wisconsin Public Service Commission, we expect an in-service date during the fourth quarter of 2015. The projected cost is \$150 million to \$170 million.

As many of you know, this winter was brutally cold in Wisconsin and the upper Midwest. Given the vital need for heating, we delivered more natural gas to our retail customers during January than during any other month in history — surpassing the previous one-month record by nearly eight percent. This growth in demand clearly underscores the need to expand our natural gas distribution network in western Wisconsin.

We're also planning to convert the fuel source for our Valley Power Plant from coal to natural gas. Located near downtown Milwaukee, Valley generates electricity, provides voltage support for our distribution network, and produces steam heating for more than 400 customers in the downtown Milwaukee business center.

Converting Valley to natural gas will reduce our operating costs and enhance the environmental performance of the units. The Wisconsin commission voted to approve the project in February. We plan to complete the Valley conversion by 2016 at an estimated cost of $65 million to $70 million.

We delivered more natural gas to our retail customers during January than during any other month in history — surpassing the previous one-month record by nearly eight percent.

At our Oak Creek expansion units, we're also making progress on our fuel flexibility initiative. These modern, efficient units were placed into service in 2010 and 2011. They were originally permitted to burn bituminous coal. However, the cost differential between bituminous coal and Powder River Basin sub-bituminous coal has grown substantially — making it possible to save our customers millions of dollars by burning a blend of the two coals.

We began test burning a blend of the two fuels this past May, and the initial results are promising. We plan to continue our testing into 2015 to identify equipment modifications that may be needed to permanently increase the percentage of Powder River Basin coal in the fuel mix at Oak Creek. If significant modifications are required, we expect to seek approval from the Wisconsin commission in late 2014 or early 2015.

During the past year, we also started a new construction project at our Twin Falls hydroelectric plant on the Menominee River near Iron Mountain, Michigan. Twin Falls was built in 1912 and is licensed to operate until 2040. However, the existing powerhouse needs to be rebuilt. We expect to complete this project in 2016 at an estimated cost of $60 million to $65 million.

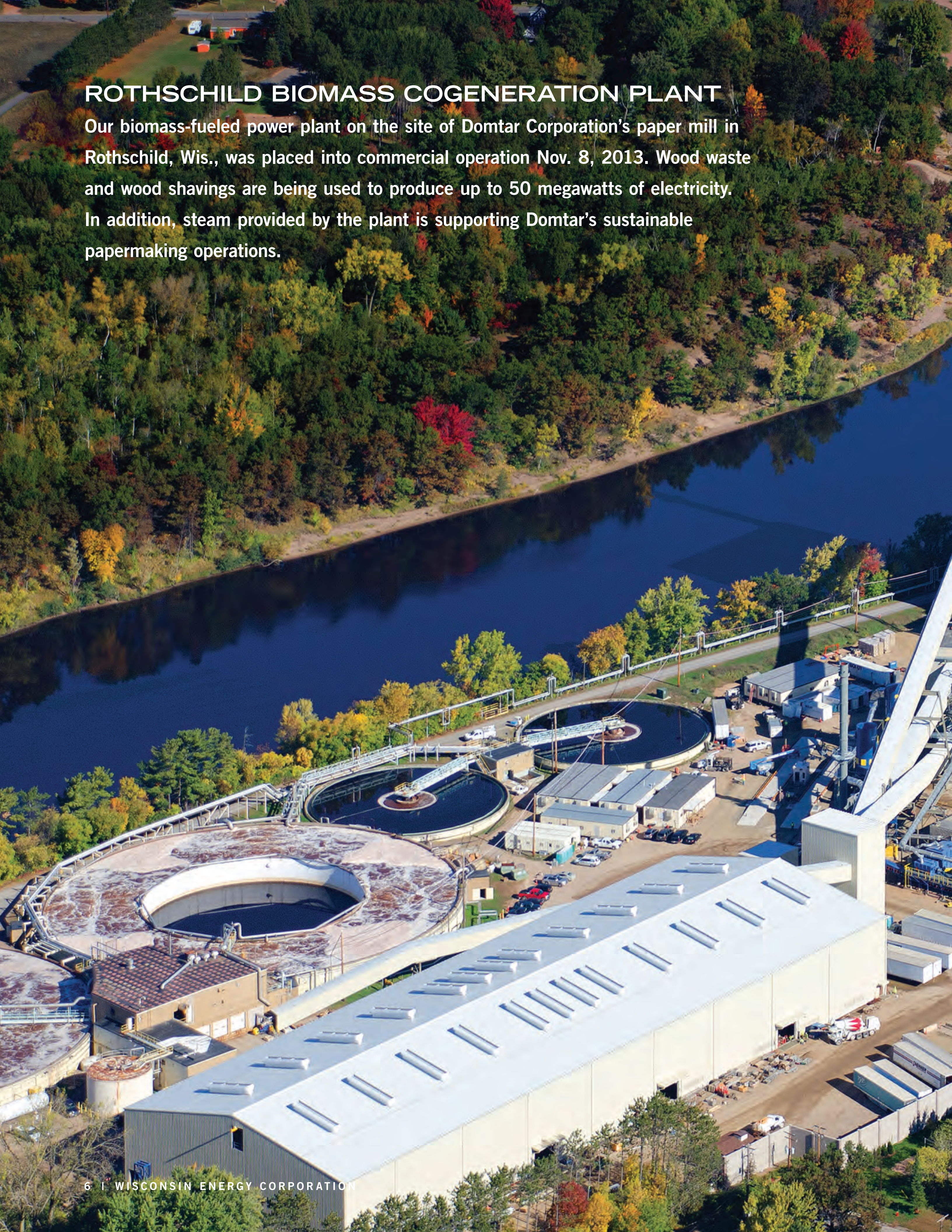

Gale Klappa and Allen Leverett

So as you can see from this brief recap of our investment plans, we really do have much to accomplish in the years ahead. And to help ensure continuity of focus and effort, we executed one element of our long-term succession plan during 2013. In July, the board of directors elected Allen Leverett president of Wisconsin Energy. Allen has been a key contributor to our success over the past decade. His election recognizes his leadership and broader operational role in the company going forward.

On behalf of our entire management team, thank you for your confidence, your support, and your investment in Wisconsin Energy as we work to **deliver the future**.

Sincerely,

Gale E. Klappa
Chairman and Chief Executive
March 4, 2014



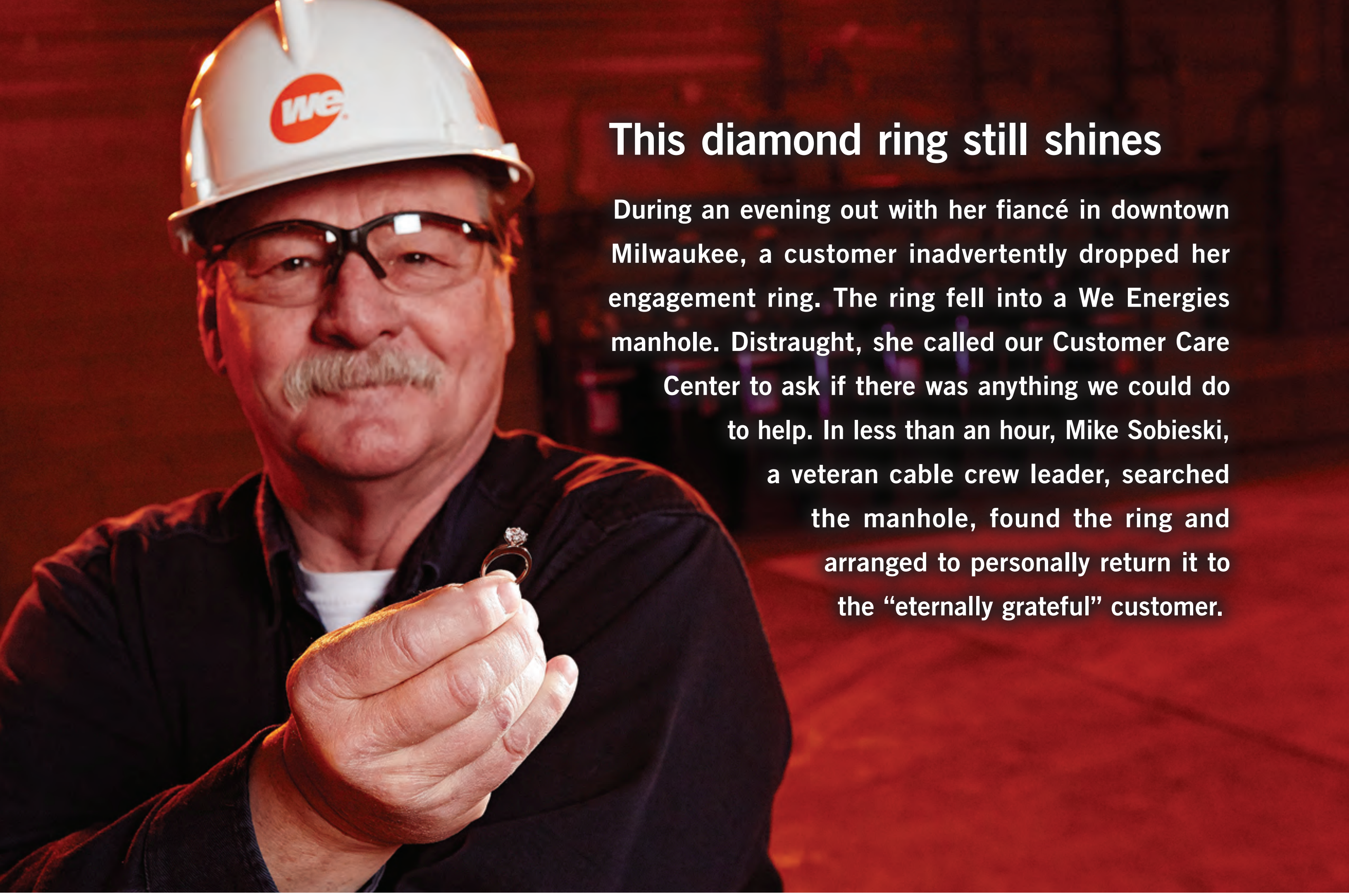
ROTHSCHILD BIOMASS COGENERATION PLANT

Our biomass-fueled power plant on the site of Domtar Corporation's paper mill in Rothschild, Wis., was placed into commercial operation Nov. 8, 2013. Wood waste and wood shavings are being used to produce up to 50 megawatts of electricity. In addition, steam provided by the plant is supporting Domtar's sustainable papermaking operations.


DUMP
BUCKET
HI-RANGER

INVESTING IN OUR DISTRIBUTION SYSTEMS

To maintain the reliability of our electric and natural gas distribution systems and our fleet of generating plants, we plan to invest between $3.2 billion and $3.5 billion over the period 2014 through 2018.



This diamond ring still shines

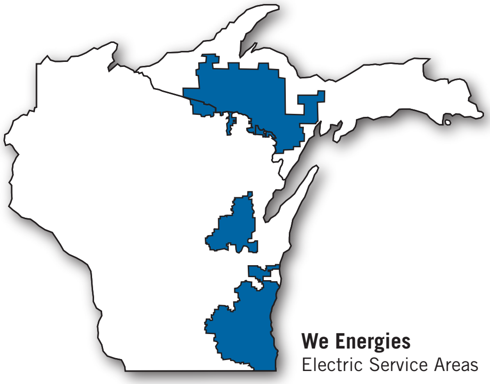
During an evening out with her fiancé in downtown Milwaukee, a customer inadvertently dropped her engagement ring. The ring fell into a We Energies manhole. Distraught, she called our Customer Care Center to ask if there was anything we could do to help. In less than an hour, Mike Sobieski, a veteran cable crew leader, searched the manhole, found the ring and arranged to personally return it to the "eternally grateful" customer.

WISCONSIN ENERGY CORPORATION (NYSE: WEC) is one of the nation's premier energy companies with more than $14 billion of assets and a diversified portfolio of businesses engaged in electric generation and the distribution of electricity, natural gas and steam.

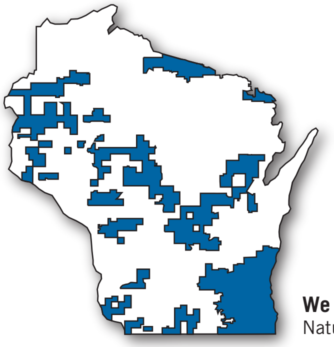
Wisconsin Energy's principal utility, We Energies, serves more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula and 1.1 million natural gas customers in Wisconsin. The company's other major subsidiary, We Power, designs, builds and owns electric generating plants.

Headquartered in Milwaukee, Wisconsin Energy is a component of the S&P 500 with more than 4,300 employees and approximately 40,000 stockholders of record.

ELECTRIC CUSTOMERS AS OF DEC. 31, 2013: 1,128,300



NATURAL GAS CUSTOMERS AS OF DEC. 31, 2013: 1,079,800



2013 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS

Wisconsin Energy Corporation

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Primary Subsidiaries	
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
MCPP	Milwaukee County Power Plant
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PIPP	Presque Isle Power Plant
PSGS	Paris Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
WECC	Wisconsin Energy Capital Corporation
Wispark	Wispark LLC
Wisvest	Wisvest LLC
Federal and State Regulatory Agencies	
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
Act 141	2005 Wisconsin Act 141
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Moody's	Moody's Investor Service
OTC	Over-the-Counter
PTF	Power the Future
RCC	Replacement Capital Covenant dated May 11, 2007
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SSR	System Support Resource
Treasury Grant	Section 1603 Renewable Energy Treasury Grant
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.
Wolverine	Wolverine Power Supply Cooperative, Inc.

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
GWh	Gigawatt-hour(s) (One GWh equals one thousand MWh)
kW	Kilowatt(s) (One kW equals one thousand Watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, retail sales and customer growth, rate actions and related filings with the appropriate regulatory authorities, current and proposed environmental regulations and other regulatory matters and related estimated expenditures, on-going legal proceedings, dividend payout ratios, projections related to the pension and other post-retirement benefit plans, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as catastrophic weather-related or terrorism-related damage; cyber-security threats and disruptions to our technology network; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; unanticipated changes in the cost or availability of materials needed to operate environmental controls at our electric generating facilities or replace and/or repair our electric and gas distribution systems; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; or collective bargaining agreements with union employees or work stoppages.

- Factors affecting the demand for electricity and natural gas, including weather and other natural phenomena; general economic conditions and, in particular, the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; energy conservation efforts; and customers moving to self-generation.

- Timing, resolution and impact of rate cases and negotiations, including recovery of costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midcontinent Independent System Operator, Inc. (MISO) Energy Markets, as well as any costs incurred as a result of customers moving to an alternative electric supplier.

- Increased competition in our electric and gas markets, including retail choice and alternative electric suppliers, and continued industry consolidation.

- Our ability to mitigate the impact of Michigan customers switching to an alternative electric supplier, including the receipt of adequate System Support Resource (SSR) payments.

- The ability to control costs and avoid construction delays during the development and construction of new electric generation facilities, as well as upgrades to our generation fleet and electric and natural gas distribution systems.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; regulatory initiatives regarding deregulation and restructuring of the electric and/or gas utility industry; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cyber security threats; the regulatory approval process for new generation and transmission facilities and new pipeline construction; changes in environmental, federal and state energy, tax and other laws and regulations to which we are subject; changes in allocation of energy assistance, including state public benefits funds; changes in the application or enforcement of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

- Current and future litigation, regulatory investigations, proceedings or inquiries, including Federal Energy Regulatory Commission (FERC) matters and Internal Revenue Service (IRS) and state tax audits and other tax matters.

- Events in the global credit markets that may affect the availability and cost of capital.

- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.

- Inflation rates.

- The investment performance of our pension and other post-retirement benefit trusts.

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings, as well as the ability of ATC and the Duke-American Transmission Company to obtain the required approvals for their transmission projects.

- The impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 and any related regulations.

- The effect of accounting pronouncements issued periodically by standard setting bodies.

- Advances in technology that result in competitive disadvantages and create the potential for impairment of existing assets.

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters.

- The ability to obtain and retain short- and long-term contracts with wholesale customers.

- Potential strategic business opportunities, including acquisitions and/or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to us.

- Incidents affecting the U.S. electric grid or operation of generating facilities.

- The cyclical nature of property values that could affect our real estate investments.

- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Foreign governmental, economic, political and currency risks.

- Other factors discussed elsewhere in this report and that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise

BUSINESS OF THE COMPANY

Wisconsin Energy Corporation was incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries.

We conduct our operations primarily in two reportable segments: a utility energy segment and a non-utility energy segment. Our primary subsidiaries are Wisconsin Electric Power Company (Wisconsin Electric), Wisconsin Gas LLC (Wisconsin Gas) and W.E. Power, LLC (We Power).

Utility Energy Segment: Our utility energy segment consists of Wisconsin Electric and Wisconsin Gas, operating together under the trade name of "We Energies." We Energies serves approximately 1,128,300 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,079,800 gas customers in Wisconsin and approximately 445 steam customers in metropolitan Milwaukee, Wisconsin.

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power, which owns and leases to Wisconsin Electric generation plants constructed as part of our Power the Future (PTF) strategy. All four of the plants constructed as part of PTF have been placed in service. Port Washington Generating Station Unit 1 (PWGS 1) and Port Washington Generating Station Unit 2 (PWGS 2) are being leased to Wisconsin Electric under long-term leases that run for 25 years. Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2) are being leased to Wisconsin Electric under long-term leases that run for 30 years.

For further financial information about our business segments, see Results of Operations in Management’s Discussion and Analysis of Financial Condition and Results of Operations and Note O -- Segment Reporting in the Notes to Consolidated Financial Statements.

CORPORATE DEVELOPMENTS AND STRATEGY

We have three primary investment opportunities and earnings streams: our regulated utility business; our investment in ATC; and our generation plants within our non-utility energy segment.

Our regulated utility business primarily consists of electric generation assets and the electric and gas distribution assets that serve our electric and gas customers under the trade name of We Energies. We Energies operates under a traditional rate regulated cost of service environment. During 2013, our regulated utility earned $719.4 million of operating income. Over the next five years, we expect to invest between $3.1 billion and $3.3 billion in this business.

We have a 26.2% ownership interest in ATC, a MISO member company regulated by FERC. Our investment in ATC totaled $402.7 million as of December 31, 2013, and our 2013 pre-tax earnings from ATC totaled $68.5 million. Over the next five years, in addition to any potential investment through our undistributed earnings in ATC, we expect to make capital contributions of approximately $130 million in ATC as it continues to invest in transmission projects.

Our non-utility energy segment consists primarily of the four generation plants constructed as part of our PTF strategy. All four plants have been placed in service and are being leased to Wisconsin Electric under long-term leases that run for 25 years (PWGS 1 and PWGS 2) and 30 years (OC 1 and OC 2). We recognize revenues on a levelized basis over the life of the leases. Our operating income from our non-utility business totaled $367.1 million during 2013, and we expect comparable earnings from this segment in 2014. The PTF strategy was developed with the primary goal of constructing these power plants. Over the next five years, we do, however, expect to invest approximately $117 million in this segment on smaller capital projects, including the Oak Creek expansion fuel flexibility project. For additional information on this project, see Factors Affecting Results, Liquidity and Capital Resources -- Other Matters.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2013, 2012 and 2011:

Wisconsin Energy Corporation	2013	2012	2011
		(Millions of Dollars)	
Utility Energy	$ 719.4	$ 647.7	$ 544.8
Non-Utility Energy	367.1	358.8	348.9
Corporate and Other	(6.4)	(6.2)	(6.4)
Total Operating Income	1,080.1	1,000.3	887.3
Equity in Earnings of Transmission Affiliate	68.5	65.7	62.5
Other Income and Deductions, net	18.8	34.8	62.7
Interest Expense, net	252.1	248.2	235.8
Income from Continuing Operations Before Income Taxes	915.3	852.6	776.7
Income Tax Expense	337.9	306.3	263.9
Income from Continuing Operations	577.4	546.3	512.8
Income from Discontinued Operations, Net of Tax	—	—	13.4
Net Income	$ 577.4	$ 546.3	$ 526.2
Diluted Earnings Per Share			
Continuing Operations	$ 2.51	$ 2.35	$ 2.18
Discontinued Operations	—	—	0.06
Total Diluted Earnings Per Share	$ 2.51	$ 2.35	$ 2.24

An analysis of contributions to operating income by segment and a more detailed analysis of results follows.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The following table summarizes our utility energy segment's operating income during 2013, 2012 and 2011:

Utility Energy Segment	2013	2012	2011
		(Millions of Dollars)	
Operating Revenues			
Electric	$ 3,308.7	$ 3,193.9	$ 3,211.3
Gas	1,113.7	962.6	1,181.2
Other	39.6	34.3	39.0
Total Operating Revenues	4,462.0	4,190.8	4,431.5
Operating Expenses			
Fuel and Purchased Power	1,158.1	1,103.8	1,174.5
Cost of Gas Sold	674.1	545.8	728.7
Other Operation and Maintenance	1,522.0	1,476.5	1,613.4
Depreciation and Amortization	320.2	296.4	257.0
Property and Revenue Taxes	116.2	120.6	113.1
Total Operating Expenses	3,790.6	3,543.1	3,886.7
Treasury Grant	48.0	—	—
Operating Income	$ 719.4	$ 647.7	$ 544.8

2013 vs. 2012: Our utility energy segment contributed $719.4 million of operating income during 2013 compared with $647.7 million of operating income during 2012. The increase in operating income was primarily caused by favorable winter weather during 2013 and pricing increases, partially offset by an increase in operation and maintenance expense and depreciation.

2012 vs. 2011: Our utility energy segment contributed $647.7 million of operating income during 2012 compared with $544.8 million of operating income during 2011. The increase in operating income was primarily caused by decreased other operation and maintenance expense and decreased fuel and purchased power expenses.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2013 with similar information for 2012 and 2011, including a summary of electric operating revenues and electric sales by customer class:

Electric Utility Operations	Electric Revenues and Gross Margin			MWh Sales		
	2013	2012	2011	2013	2012	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$ 1,208.6	$ 1,163.9	$ 1,159.2	8,141.9	8,317.7	8,278.5
Small Commercial/Industrial	1,048.0	1,013.6	1,006.9	8,860.4	8,860.0	8,795.8
Large Commercial/Industrial	711.9	744.3	763.7	8,673.4	9,710.7	9,992.2
Other - Retail	23.4	22.8	22.9	152.3	154.8	153.6
Total Retail	2,991.9	2,944.6	2,952.7	25,828.0	27,043.2	27,220.1
Wholesale - Other	143.7	144.4	154.0	1,953.5	1,566.6	2,024.8
Resale - Utilities	143.2	53.4	69.5	4,382.7	1,642.4	2,065.7
Other Operating Revenues	28.4	51.5	35.1	—	—	—
Total	3,307.2	3,193.9	3,211.3	32,164.2	30,252.2	31,310.6
Electric Customer Choice (a)	1.5	—	—	813.0	—	—
Total, including electric customer choice	3,308.7	3,193.9	3,211.3			
Fuel and Purchased Power						
Fuel	611.1	541.6	644.4			
Purchased Power	533.4	548.7	514.8			
Total Fuel and Purchased Power	1,144.5	1,090.3	1,159.2			
Total Electric Gross Margin	$ 2,164.2	$ 2,103.6	$ 2,052.1			
Weather - Degree Days (b)						
Heating (6,580 Normal)				7,233	5,704	6,633
Cooling (730 Normal)				688	1,041	793

(a) Represents distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.
(b) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

Electric Utility Revenues and Sales

2013 vs. 2012: Our electric utility operating revenues increased by $114.8 million, or 3.6%, when compared to 2012. The most significant factors that caused a change in revenues were:

- Wisconsin net retail pricing increases of $115.6 million ($177.7 million less $62.1 million related to Section 1603 Renewable Energy Treasury Grant (Treasury Grant) bill credits), which is primarily related to our 2013 Wisconsin Rate Case. For information on the Treasury Grant and the rate order in the 2013 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Accounting Developments and -- Utility Rates and Regulatory Matters, respectively.
- A $89.8 million increase in sales for resale due to increased sales into the MISO Energy Markets as a result of increased availability of our generating units.
- A $48.0 million decrease in large commercial/industrial sales due to the two iron ore mines that switched to an alternative electric supplier effective September 1, 2013. See Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring

and Competition -- Restructuring in Michigan, for a discussion of the impact of industry restructuring in Michigan on our electric sales.

- A $23.1 million decrease in other operating revenues, primarily driven by the amortization of $25.9 million in 2012 related to the settlement with the United States Department of Energy (DOE). For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2012 Fuel Cost Plan Request.
- A return to more normal summer weather as compared to the prior year that decreased electric revenues by an estimated $17.7 million.

As measured by cooling degree days, 2013 was 5.8% cooler than normal, and 33.9% cooler than 2012. Residential sales decreased by 2.1%, primarily due to the weather. Sales to our large commercial/industrial customers decreased by 10.7% primarily because of a decrease in sales to the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 3.0%. The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Wholesale - Other sales increased 24.7% primarily due to increased off-peak energy sales which generate lower incremental revenue because the majority of our wholesale revenue is tied to demand.

2012 vs. 2011: Our electric utility operating revenues decreased by $17.4 million, or 0.5%, when compared to 2011. The most significant factors that caused a change in revenues were:

- Favorable weather as compared to 2011 that increased electric revenues by an estimated $28.5 million.
- Other operating revenues increased by approximately $16.4 million, driven by the $25.9 million amortization of the settlement with the DOE.
- A planned outage at an iron ore mine in 2012 and the conversion to self-generation of two other large customers decreased electric revenues by an estimated $20.4 million.
- A $16.2 million reduction in sales for resale due to reduced sales into the MISO Energy Markets.
- Lower MWh sales to our wholesale customers, which decreased revenue by an estimated $12.4 million as compared to 2011.

As measured by cooling degree days, 2012 was 49.6% warmer than normal, and 31.3% warmer than 2011. We believe the warmer summer weather was the primary reason for the 0.5% increase in residential sales and the 0.7% increase in small commercial/industrial sales. The increase due to warmer summer weather was partially offset by reduced sales from warmer winter weather in the first quarter of 2012 as compared to the first quarter of 2011.

Sales to our large commercial/industrial customers decreased by 2.8% primarily due to the planned outage at one of the iron ore mines in Michigan and the conversion to self-generation of two other large customers. Excluding sales to these three customers, MWh sales to large commercial/industrial customers increased by 1.1%. Wholesale sales decreased primarily due to the low market price of power in 2012 as compared to 2011, which caused some of these customers to obtain energy from the MISO market rather than through our contracts. The reduction did not impact the majority of revenue received from these customers, which is tied to demand. The lower market price of power also reduced our ability to sell energy into the MISO Energy Markets.

Electric Fuel and Purchased Power Expenses

2013 vs. 2012: Our electric fuel and purchased power costs increased by $54.2 million, or approximately 5.0%, when compared to 2012. This increase was primarily caused by a 6.3% increase in total MWh sales, partially offset by a decrease in our average cost of fuel because of outage timing and a decrease in coal costs.

2012 vs. 2011: Our electric fuel and purchased power costs decreased by $68.9 million, or approximately 5.9%, when compared to 2011. This decrease was primarily caused by a 3.4% decrease in total MWh sales as well as a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

The following table compares our total gas utility operating revenues and gross margin (total gas utility operating revenues less cost of gas sold) during 2013, 2012 and 2011.

Gas Utility Operations	2013	2012	2011
	(Millions of Dollars)		
Operating Revenues	$ 1,113.7	$ 962.6	$ 1,181.2
Cost of Gas Sold	674.1	545.8	728.7
Gross Margin	$ 439.6	$ 416.8	$ 452.5

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under Gas Cost Recovery Mechanisms (GCRMs). The following table compares our gas utility gross margin and therm deliveries by customer class during 2013, 2012 and 2011:

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2013	2012	2011	2013	2012	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$ 284.2	$ 267.9	$ 290.2	872.0	676.4	776.8
Commercial/Industrial	96.5	88.8	101.5	499.9	390.6	461.7
Interruptible	1.8	1.7	1.8	18.1	14.6	16.0
Total Retail	382.5	358.4	393.5	1,390.0	1,081.6	1,254.5
Transported Gas	51.7	52.9	52.6	1,052.8	1,140.4	899.6
Other Operating	5.4	5.5	6.4	—	—	—
Total	$ 439.6	$ 416.8	$ 452.5	2,442.8	2,222.0	2,154.1
Weather - Degree Days (a)						
Heating (6,580 Normal)				7,233	5,704	6,633

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

2013 vs. 2012: Our total retail gas margin increased by $24.1 million, or approximately 6.7%, when compared to 2012. We estimate that colder winter weather increased gas margins by approximately $56.9 million. As measured by heating degree days, 2013 was 26.8% colder than 2012 and 9.9% colder than normal. Gas margins were reduced by $42.3 million because of lower gas rates that became effective January 1, 2013.

2012 vs. 2011: Our total retail gas margin decreased by $35.1 million, or approximately 8.9%, when compared to 2011 primarily because of a decrease in sales volumes as a result of warmer winter weather. As measured by heating degree days, 2012 was 14.0% warmer than 2011 and 14.4% warmer than normal.

Transported gas volumes increased by 26.8% when compared to 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin.

Other Operation and Maintenance Expense

2013 vs. 2012: Our other operation and maintenance expense increased by $45.5 million, or approximately 3.1%, when compared to 2012. This increase was primarily driven by the reinstatement of $148.0 million of regulatory amortizations, offset in part by a $50.1 million reduction in bad debt expense related to our natural gas customers and continued cost control efforts across our utilities. For additional information on the regulatory amortizations, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2012 Wisconsin Rate Case.

Our utility operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages and amortization of regulatory assets.

2012 vs. 2011: Our other operation and maintenance expense decreased by $136.9 million, or approximately 8.5%, when compared to 2011. This decrease is primarily due to the one year suspension of $148.0 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case.

Depreciation and Amortization Expense

2013 vs. 2012: Depreciation and Amortization expense increased by $23.8 million, or approximately 8.0%, when compared to 2012. This increase was primarily because of an overall increase in utility plant in service. The emission control equipment for units 5 and 6 of the Oak Creek Air Quality Control System (AQCS) project went into service in March 2012, and for units 7 and 8 in September 2012. In addition, our new biomass plant went into service in November 2013. For additional information on the AQCS and biomass facility, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System and -- Renewables, Efficiency, and Conservation, respectively.

We expect depreciation and amortization expense to increase in 2014 primarily as a result of an increase in utility plant in service related to the biomass plant, which will have been in service a full year.

2012 vs. 2011: Depreciation and Amortization expense increased by $39.4 million, or approximately 15.3%, when compared to 2011. This increase was primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011. In addition, the emission control equipment for units 5 and 6 of the Oak Creek AQCS project went into service in March 2012, and for units 7 and 8 in September 2012.

Treasury Grant

During 2013, we recognized $48 million of income related to a Treasury Grant associated with our recently completed biomass plant. The grant income that we recognized in income is equal to the bill credits provided to our retail electric customers in Wisconsin before related tax benefits. For additional information on the Treasury Grant, see Factors Affecting Results, Liquidity and Capital Resources -- Accounting Developments.

During 2014, we expect to recognize approximately $13 million of grant income. This amount is equal to the bill credits we expect to provide to our retail electric customers in Wisconsin before related tax benefits.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (PWGS 1, PWGS 2, OC 1 and OC 2).

This segment reflects the lease revenues on the new units as well as the depreciation expense. Operating and maintenance costs and limited management fees associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	2013	2012	2011
	(Millions of Dollars)		
Operating Revenues	$ 446.7	$ 439.9	$ 435.1
Operation and Maintenance Expense	12.5	14.0	13.7
Depreciation Expense	67.1	67.1	72.5
Operating Income	$ 367.1	$ 358.8	$ 348.9

2013 vs. 2012: Non-utility energy segment operating income increased $8.3 million, or approximately 2.3%, when compared to 2012. The increase primarily relates to the increase in operating revenues related to the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case.

In 2014, we expect our non-utility energy segment operating revenue to stay relatively flat compared to 2013.

2012 vs. 2011: Non-utility energy segment operating income increased $9.9 million, or approximately 2.8%, when compared to 2011. This increase primarily relates to a decrease in depreciation expense related to finalized depreciable lives of the Oak Creek expansion units and a full year's earnings in 2012 for OC 2 compared to eleven and a half months of earnings for 2011.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2013 vs. 2012: Corporate and other affiliates had an operating loss of $6.4 million in 2013 compared with an operating loss of $6.2 million in 2012.

2012 vs. 2011: Corporate and other affiliates had an operating loss of $6.2 million in 2012 compared with an operating loss of $6.4 million in 2011.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Equity	$ 18.3	$ 35.3	$ 59.4
Other, net	0.5	(0.5)	3.3
Total Other Income and Deductions, net	$ 18.8	$ 34.8	$ 62.7

2013 vs. 2012: Other income and deductions, net decreased by approximately $16.0 million, or 46.0%, when compared to 2012. This decrease primarily relates to lower AFUDC - Equity related to the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8, partially offset by the biomass plant which went into service in November 2013.

During 2014, we expect to see a reduction in AFUDC - Equity as we expect to have fewer large construction projects.

2012 vs. 2011: Other income and deductions, net decreased by approximately $27.9 million, or 44.5%, when compared to 2011. This decrease primarily relates to lower AFUDC - Equity related to the Glacier Hills Wind Park, which went into service in December 2011, as well as the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2013	2012	2011
	(Millions of Dollars)		
Gross Interest Costs	$ 261.5	$ 264.1	$ 262.5
Less: Capitalized Interest	9.4	15.9	26.7
Interest Expense, net	$ 252.1	$ 248.2	$ 235.8

2013 vs. 2012: Our net interest expense increased by $3.9 million, or 1.6%, as compared to 2012 primarily because of lower capitalized interest. Our capitalized interest decreased by $6.5 million primarily because of lower construction work in progress.

During 2014, we expect to see slightly lower net interest expense as gross interest costs are expected to decrease due to a lower weighted average embedded interest rate on our long-term debt. We expect this decrease will be partially offset by a reduction in capitalized interest as a result of the biomass plant going into service in 2013.

2012 vs. 2011: Our net interest expense increased by $12.4 million, or 5.3%, as compared to 2011 primarily because of lower capitalized interest. Our capitalized interest decreased by $10.8 million primarily because we stopped capitalizing interest on the Oak Creek AQCS project when the emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8, and the Glacier Hills Wind Park which went into service in December 2011.

CONSOLIDATED INCOME TAX EXPENSE

2013 vs. 2012: Our effective tax rate applicable to continuing operations was 36.9% in 2013 compared to 35.9% in 2012. This increase in our effective tax rate was due to reduced domestic production activities deductions and AFUDC - Equity. For further information, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2014 annual effective tax rate to be between 37.5% and 38.5%.

2012 vs. 2011: Our effective tax rate applicable to continuing operations was 35.9% in 2012 compared to 34.0% in 2011. This increase in our effective tax rate was primarily the result of decreased AFUDC - Equity.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2013, 2012 and 2011:

	2013	2012	2011
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$ 1,231.0	$ 1,173.9	$ 993.4
Investing Activities	$ (745.8)	$ (729.6)	$ (892.5)
Financing Activities	$ (494.8)	$ (422.8)	$ (111.3)

Operating Activities

2013 vs. 2012: Cash provided by operating activities was $1,231.0 million during 2013, which was an increase of $57.1 million over 2012. The increase is primarily because of lower contributions to our qualified benefit plans and higher non-cash charges to earnings. During 2013, we made no contributions to our qualified benefit plans, compared to contributions of $100 million during 2012. In addition, we had higher net income, depreciation expense and amortization expense. Included in the higher amortization expense is a $77.9 million increase in the amortization of regulatory items. Partially offsetting these items is an increase in accounts receivable and accrued revenues of $201.2 million because of colder winter weather and the Treasury Grant.

2012 vs. 2011: Cash provided by operating activities was $1,173.9 million during 2012, which was an increase of $180.5 million over 2011. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, and lower contributions to our benefit plans. Combined these items increased operating cash flows by $232.8 million as compared to 2011. Partially offsetting these items, our non-cash charges related to the amortization of certain regulatory assets and liabilities was $148.0 million lower during 2012 as compared to 2011 because the Public Service Commission of Wisconsin (PSCW) allowed us to suspend these amortizations in 2012.

Investing Activities

2013 vs. 2012: Cash used in investing activities was $745.8 million during 2013, which was $16.2 million higher than 2012. Our change in restricted cash decreased by $40.1 million, which is related to the 2012 release of restricted cash through bill credits and the reimbursement of costs associated with the DOE settlement. Our capital expenditures decreased by $19.6 million during 2013 as compared to 2012, primarily because of decreased spending as the Oak Creek AQCS project went into service in 2012.

The following table identifies capital expenditures by year:

Capital Expenditures	2013	2012	2011
		(Millions of Dollars)	
Utility	$ 657.9	$ 697.3	$ 792.2
We Power	26.1	5.5	31.2
Other	3.4	4.2	7.4
Total Capital Expenditures	$ 687.4	$ 707.0	$ 830.8

2012 vs. 2011: Cash used in investing activities was $729.6 million during 2012, which was $162.9 million lower than 2011. This decrease was primarily caused by a decrease in capital expenditures and a decrease in our restricted cash. Our capital expenditures decreased by $123.8 million in 2012 compared to 2011, primarily because of decreased spending on the Oak Creek AQCS project which went into service in March and September of 2012. In 2011, we received $45.5 million in proceeds from the settlement with the DOE. The proceeds were treated as restricted cash, which was recorded as cash used in investing activities. In 2012, we released $42.8 million of the proceeds through bill credits and the reimbursement of costs. The decrease was offset by a reduction in proceeds from asset sales. In 2011, we received proceeds from asset sales totaling $41.5 million, which primarily relates to the sale of our interest in Edgewater Generating Unit 5, as compared to proceeds of $8.7 million in 2012.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2013	2012	2011
	(Millions of Dollars)		
Dividends on Common Stock	$ (328.9)	$ (276.3)	$ (242.0)
Common Stock Repurchased, Net	(174.9)	(103.4)	(139.5)
Net Increase (Decrease) in Debt	(3.4)	(43.8)	265.4
Other	12.4	0.7	4.8
Cash Used in Financing	$ (494.8)	$ (422.8)	$ (111.3)

2013 vs. 2012: Cash used in financing activities was $494.8 million during 2013, compared to $422.8 million during 2012. Our dividends paid on common stock increased by $52.6 million during 2013 as compared to 2012, as a result of increases in the quarterly common stock dividend of 13.3% and 12.5% in the first and third quarter, respectively. In addition, on May 5, 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. In 2013, we repurchased approximately 3.0 million shares in the open market pursuant to this program at a total cost of $126.0 million, compared to 1.5 million shares at a cost of $51.8 million in 2012.

2012 vs. 2011: Cash used in financing activities was $422.8 million during 2012, compared to $111.3 million during 2011. In 2012, we issued $251.8 million in long term debt, including $250.0 million by Wisconsin Electric, and used the proceeds to repay short-term debt and for other general corporate purposes. In 2011, we issued $720.0 million of long-term debt. In addition, we retired $466.6 million of long-term debt in 2011. Short-term debt decreased $275.3 million in 2012 compared to a $12.0 million increase in 2011. In addition, our common stock dividends increased in 2012 as we raised our quarterly dividend rate by 15.4%.

No new shares of Wisconsin Energy's common stock were issued in 2013, 2012 or 2011. During these years, our independent plan agents purchased, in the open market, 2.4 million shares at a cost of $97.4 million, 2.8 million shares at a cost of $101.4 million and 3.0 million shares at a cost of $93.9 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2013, 2012 and 2011, we received proceeds of $48.5 million, $49.8 million and $54.4 million, respectively, related to the exercise of stock options. In addition, we instructed our independent agents to purchase shares of our common stock in the open market to satisfy our obligations under our stock purchase and dividend reinvestment plan and various employee benefit plans.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

We anticipate meeting our capital requirements during 2014 and beyond primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities depending on market conditions and other factors.

We currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets and internally generated cash.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2013, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities. As of December 31, 2013, we had approximately $537.4 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2013, our maximum commercial paper outstanding was $594.5 million with a weighted-average interest rate of 0.25%. For additional information regarding our commercial paper balances during 2013, see Note K -- Short-Term Debt in the Notes to Consolidated Financial Statements.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities as of December 31, 2013:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$ 400.0	$ 0.1	$ 399.9	December 2017
Wisconsin Electric	$ 500.0	$ 6.1	$ 493.9	December 2017
Wisconsin Gas	$ 350.0	$ —	$ 350.0	December 2017

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our capitalization structure as of December 31, 2013 and 2012, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 (Junior Notes):

	2013		2012	
Capitalization Structure	Actual	Adjusted	Actual	Adjusted
	(Millions of Dollars)			
Common Equity	$ 4,233.0	$ 4,483.0	$ 4,135.1	$ 4,385.1
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,705.4	4,455.4	4,865.9	4,615.9
Short-Term Debt	537.4	537.4	394.6	394.6
Total Capitalization	$ 9,506.2	$ 9,506.2	$ 9,426.0	$ 9,426.0
Total Debt	$ 5,242.8	$ 4,992.8	$ 5,260.5	$ 5,010.5
Ratio of Debt to Total Capitalization	55.2%	52.5%	55.8%	53.2%

For a summary of the interest rate, maturity and amount outstanding of each series of our long-term debt on a consolidated basis, see the Consolidated Statements of Capitalization.

Included in Long-Term Debt on our Consolidated Balance Sheets as of December 31, 2013 and 2012 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

The adjusted presentation of our consolidated capitalization structure is presented as a complement to our capitalization structure presented in accordance with Generally Accepted Accounting Principles (GAAP). Management evaluates and manages Wisconsin Energy's capitalization structure, including its total debt to total capitalization ratio, using the GAAP calculation as adjusted by the rating agency treatment of the Junior Notes. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

As described in Note H -- Common Equity, in the Notes to Consolidated Financial Statements, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

Wisconsin Electric is the obligor under two series of tax exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of December 31, 2013, the repurchased bonds were still outstanding, but were not reported as long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

On December 5, 2013, the Board of Directors reviewed management's plan to maintain an appropriate capital structure by retiring up to $500 million of the holding company's obligations during the period 2014 through 2017.

Bonus Depreciation Provisions

The American Taxpayer Relief Act of 2012 was signed into law on January 2, 2013, which extended the 50% bonus depreciation rules to include assets placed in service in 2013. These rules apply to the biomass plant we constructed in Rothschild, which went into service in November 2013. As a result of the increased federal tax depreciation for 2013 and prior years, we did not make federal income tax payments for 2013 and do not anticipate making federal income tax payments for 2014.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at Standard & Poor's Ratings Services (S&P) and/or Baa3 at Moody's Investor Service (Moody's). As of December 31, 2013, we estimate that the collateral or the termination payments required under these agreements totaled approximately $214.6 million. Generally, collateral may be provided by a Wisconsin Energy guaranty, letter of credit or cash. We also have other commodity contracts that in the event of a credit rating downgrade could result in a reduction of our unsecured credit granted by counterparties.

In addition, access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

In January 2014, Moody's raised the ratings of Wisconsin Energy (senior unsecured to A2 from A3; junior subordinated to A3 from Baa1; commercial paper to P-1 from P-2), Wisconsin Electric (senior unsecured to A1 from A2), Wisconsin Gas (senior unsecured to A1 from A2), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes to A1 from A2) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured to A2 from A3). The commercial paper ratings of Wisconsin Electric and Wisconsin Gas remained at P-1. Moody's assigned a stable ratings outlook to each company.

In December 2013, S&P raised the ratings of Wisconsin Gas commercial paper to A-1 from A-2, and senior unsecured to A from A-. S&P also affirmed the stable rating outlook.

In June 2013, S&P affirmed the ratings of Wisconsin Energy (commercial paper, A-2; senior unsecured, BBB+; junior subordinated, BBB), Wisconsin Electric (commercial paper, A-2; senior unsecured, A-), Wisconsin Gas (commercial paper, A-2; senior unsecured, A-), WECC (senior unsecured, A-) and ERGSS (senior notes, A-). S&P also revised the ratings outlooks assigned to each company from positive to stable.

In June 2013, Fitch Ratings (Fitch) affirmed the ratings of Wisconsin Energy (commercial paper, F2; senior unsecured, A-; junior subordinated, BBB), Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1), WECC (senior unsecured, A-) and ERGSS (senior notes, A+). At the same time, Fitch lowered the senior unsecured rating of Wisconsin Gas to A from A+. Fitch also affirmed the stable ratings outlooks assigned to each company.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

Capital Requirements

Capital Expenditures: Our estimated capital expenditures for the next three years are as follows:

Capital Expenditures	2014	2015	2016
	(Millions of Dollars)		
Utility	$ 667.9	$ 777.6	$ 587.6
We Power	38.6	19.8	28.7
Other	4.5	6.8	5.5
Total	$ 711.0	$ 804.2	$ 621.8

The majority of spending consists of upgrading our electric and gas distribution systems. Our actual future long-term capital requirements may vary from these estimates because of changing environmental and other regulations such as air quality standards, renewable energy standards and electric reliability initiatives that impact our utility energy segment.

Common Stock Matters: On December 5, 2013, our Board of Directors authorized a new share repurchase program for up to $300 million of our common stock from January 1, 2014 through the end of 2017. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time.

In addition, on January 16, 2014, our Board of Directors increased our quarterly common stock dividend to $0.39 per share, up approximately 2.0%, from $0.3825 per share.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately $1.8 billion as of December 31, 2013. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2013, we made no contributions to our qualified pension plans or our qualified Other Post-Retirement Employee Benefit (OPEB) plans. During 2012, we contributed $95.6 million to our qualified pension plans and $4.4 million to our qualified OPEB plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note N -- Benefits in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For additional information, see Note F -- Variable Interest Entities in the Notes to Consolidated Financial Statements in this report.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2013:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	$ 8,709.7	$ 556.3	$ 917.8	$ 674.8	$ 6,560.8
Capital Lease Obligations (c)	215.9	41.9	88.6	28.6	56.8
Operating Lease Obligations (d)	40.5	3.9	7.6	6.3	22.7
Purchase Obligations (e)	12,189.3	892.3	1,309.4	1,067.9	8,919.7
Other Long-Term Liabilities	1,000.1	104.1	199.4	201.0	495.6
Total Contractual Obligations	$ 22,155.5	$ 1,598.5	$ 2,522.8	$ 1,978.6	$ 16,055.6

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates.

(b) Principal and interest payments on Long-Term Debt (excluding capital lease obligations).

(c) Capital Lease Obligations of Wisconsin Electric for power purchase commitments. This amount does not include We Power leases to Wisconsin Electric which are eliminated upon consolidation.

(d) Operating Lease Obligations for power purchase commitments and rail car leases.

(e) Purchase Obligations under various contracts for the procurement of fuel, power, gas supply and associated transportation related to utility operations and for construction, information technology and other services for utility and We Power operations. This includes the power purchase agreement for Point Beach.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note G -- Income Taxes in the Notes to Consolidated Financial Statements in this report.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery: Our utility energy segment accounts for its regulated operations in accordance with accounting guidance for regulated entities. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. Regulated entities are allowed to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators, and recovery of these deferred costs in future rates is subject to the review and approval of those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by our regulators, the costs are charged to income in the current period. In general, regulatory assets are recovered in a period between one to eight years. Regulatory assets associated with pension and OPEB expenses are amortized as a component of pension and OPEB expense. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. As of December 31, 2013, our regulatory assets totaled $1,108.5 million and our regulatory liabilities totaled $879.1 million.

Commodity Prices: In the normal course of providing energy, we are subject to market fluctuations of the costs of coal, natural gas, purchased power and fuel oil used in the delivery of coal. We manage our fuel and gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas and electric hedging programs.

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of Wisconsin Electric's risk of electric fuel cost fluctuation. The fuel rules allow for a deferral of prudently incurred fuel costs that fall outside of a symmetrical band (plus or minus 2%). Under the rules, any over or under-collection of fuel costs deferred at the end of the year would be incorporated into fuel cost recovery rates in future years. For information regarding the fuel rules, see Utility Rates and Regulatory Matters -- Wisconsin Fuel Proceedings.

Natural Gas Costs: Higher natural gas costs could increase our working capital requirements and result in higher gross receipts taxes in the state of Wisconsin. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Higher natural gas costs may also lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution.

As part of its December 2012 rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs through December 31, 2014. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceeds or is less than amounts allowed in rates.

As a result of GCRMs, our gas utility operations receive dollar for dollar recovery on the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative fuel sources, which could reduce future gas margins. For information concerning the natural gas utilities' GCRMs, see Utility Rates and Regulatory Matters.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Wisconsin Electric's electric revenues and sales are unfavorably sensitive to below normal temperatures during the summer cooling season, and to some extent, to above normal temperatures during the winter heating season. Our gas revenues and sales are unfavorably sensitive to above normal temperatures during the winter heating season. A summary of actual weather information in the utility segment's service territory during 2013, 2012 and 2011, as measured by degree days, may be found above in Results of Operations.

Interest Rate: We have various short-term borrowing arrangements to provide working capital and general corporate funds. We also have variable rate long-term debt outstanding as of December 31, 2013. Borrowing levels under these arrangements vary from period to period depending on capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis as of December 31, 2013 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2013, we had $537.4 million of commercial paper outstanding with a weighted average interest rate of 0.20% and $147.0 million of variable-rate long-term debt outstanding with a weighted average interest rate of 0.50%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $6.8 million.

Marketable Securities Return: We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

The fair value of our trust fund assets as of December 31, 2013 was approximately:

	Millions of Dollars	
Pension trust funds	$	1,451.0
Other post-retirement benefits trust funds	$	327.6

The expected long-term rate of return on plan assets for 2014 is 7.25% and 7.5%, respectively, for the pension and OPEB plans.

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

Economic Conditions: Our service territory is within the state of Wisconsin and the Upper Peninsula of Michigan. We are exposed to market risks in the regional midwest economy.

Inflation: We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, regulatory and environmental compliance and new generation in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information.

POWER THE FUTURE

All of the PTF units have been placed into service and are positioned to provide a significant portion of our future generation needs. The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2.

As part of our 2013 Wisconsin Rate Case, the PSCW determined that 100% of the construction costs for our Oak Creek expansion units were prudently incurred, and approved the recovery in rates of more than 99.5% of these costs. In addition, the PSCW deferred the final decision regarding $24 million related to the Oak Creek expansion fuel flexibility project until a future rate proceeding. See Other Matters below for additional information about the fuel flexibility project.

We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2, OC 1 and OC 2 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. Under the lease terms, our return is calculated using a 12.7% return on equity and the equity ratio is assumed to be 53% for the PWGS Units and 55% for the Oak Creek Units.

Wisconsin Electric operates PWGS 1, PWGS 2, OC 1 and OC 2 and is authorized by the PSCW to fully recover prudently incurred operating and maintenance costs in its Wisconsin electric rates. As the operator of the units, Wisconsin Electric may request We Power make capital improvements to or further investments in the units. Under the lease terms, we would expect the costs of any capital improvements or further investments to be added to the lease payments, and ultimately to be recovered in Wisconsin Electric's rates.

We Power assigned its warranty rights to Wisconsin Electric upon turnover of each of the Oak Creek expansion units. The warranty claim for costs incurred to repair steam turbine corrosion damage identified on both units was scheduled to go to arbitration in October 2013, but we entered into a settlement agreement with Bechtel Power Corporation (Bechtel) in June 2013 resolving the claim, as well as several other warranty claims. This settlement did not have a material impact to our financial statements. Bechtel and Wisconsin Electric continue to work through two remaining items.

Pursuant to the terms of this settlement agreement, Bechtel achieved final acceptance of both Oak Creek expansion units.

UTILITY RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas and steam rates in the state of Wisconsin, while FERC regulates our wholesale power, electric transmission and interstate gas transportation service rates. The MPSC regulates our retail electric rates in the state of Michigan. Within our regulated segment, for the year ended December 31, 2013, we estimate that approximately 87% of our electric revenues were regulated by the PSCW, 4% were regulated by the MPSC and the balance of our electric revenues was regulated by FERC. Because of the loss of several Michigan customers to an alternative electric supplier, the percentage of revenues regulated by the MPSC is likely to decline in the future. In Wisconsin, a general rate case is typically filed every two years. All of our natural gas and steam revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

General Rate Proceedings

2013 Wisconsin Rate Case: In March 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. In December 2012, the PSCW approved the following rate adjustments:

- A net bill increase related to non-fuel costs for Wisconsin Electric's Wisconsin retail electric customers of approximately $70 million (2.6%) for 2013. This amount reflects an offset of approximately $63 million (2.3%) of bill credits related to the proceeds of the Treasury Grant, including related tax benefits. Absent this offset, the retail electric rate increase for non-fuel costs was approximately $133 million (4.8%) for 2013.
- An electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014, and a $45 million (1.6%) reduction in bill credits.
- Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013.
- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Electric rates reflect a $6.4 million reduction in bad debt expense.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Gas rates reflect a $43.8 million reduction in bad debt expense.
- An increase of approximately $1.3 million (6.0%) for Wisconsin Electric's Downtown Milwaukee (Valley) steam utility customers for 2013 and another $1.3 million (6.0%) in 2014.
- An increase of approximately $1 million (7.0%) in 2013 and $1 million (6.0%) in 2014 for Wisconsin Electric's Milwaukee County steam utility customers.

These rate adjustments were effective January 1, 2013. In addition, the PSCW indicated that Wisconsin Electric's and Wisconsin Gas' allowed return on equity would remain at 10.4% and 10.5%, respectively. The PSCW also approved escrow accounting treatment for the Treasury Grant. In the first half of 2014, Wisconsin Electric and Wisconsin Gas expect to seek base rate increases to be effective in 2015.

2012 Wisconsin Rate Case: In May 2011, Wisconsin Electric and Wisconsin Gas filed an application with the PSCW to initiate rate proceedings. In lieu of a traditional rate proceeding, we requested an alternative approach, which resulted in no increase in 2012 base rates for our customers. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that, among other things:

- Authorizes Wisconsin Electric to suspend the amortization of $148 million of regulatory costs during 2012, with amortization to begin again in 2013.
- Authorizes $148 million of carrying costs and depreciation on previously authorized air quality and renewable energy projects, effective January 1, 2012.
- Authorizes the refund of $26 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE.

We received a final written order from the PSCW in November 2011.

2012 Michigan Rate Case: In July 2011, Wisconsin Electric filed a $17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Pursuant to Michigan law, we self-implemented a $5.7 million interim electric base rate increase in January 2012. This increase was partially offset by a refund of $2.7 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE, resulting in a net $3.0 million rate increase. In addition, approximately $2.0 million of renewable costs were included in our Michigan fuel recovery rate effective January 1, 2012. The MPSC approved a total increase in electric base rates of $9.2 million annually, effective June 27, 2012, and authorized a 10.1% return on equity. In 2014, Wisconsin Electric expects to seek a base rate increase to be effective in 2015.

2010 Wisconsin Rate Case: In March 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. In December 2009, the PSCW approved the following rate adjustments:

- An increase of approximately $85.8 million (3.35%) in retail electric rates for Wisconsin Electric;
- A decrease of approximately $2.0 million (0.35%) for natural gas service for Wisconsin Electric;
- An increase of approximately $5.7 million (0.70%) for natural gas service for Wisconsin Gas; and
- A decrease of approximately $0.4 million (1.65%) for Wisconsin Electric's Valley steam utility customers and a decrease of approximately $0.1 million (0.47%) for its Milwaukee County steam utility customers.

These rate adjustments became effective January 1, 2010. In addition, the PSCW lowered the authorized return on equity for Wisconsin Electric from 10.75% to 10.4% and for Wisconsin Gas from 10.75% to 10.5%.

As part of its final decision in the 2010 rate case, the PSCW authorized Wisconsin Electric to reopen the docket in 2010 to review updated 2011 fuel costs. In September 2010, Wisconsin Electric filed an application with the PSCW to reopen the docket to review updated 2011 fuel costs and to set rates for 2011 that reflect those costs. The PSCW issued a final decision, increasing annual Wisconsin retail rates by $25.4 million effective April 29, 2011. The net increase was driven primarily by an increase in the delivered cost of coal.

***2010 Michigan Rate Increase Request*:** In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. In July 2010, the MPSC issued its final order, approving a total increase of $23.5 million annually, or 14.2%. In August 2010, our largest customers, two iron ore mines, filed an appeal with the MPSC regarding this rate order. In October 2010, the MPSC ruled on the mines' appeal and reduced the rate increase by approximately $0.3 million annually, effective November 1, 2010. In November 2010, the mines filed a Claim of Appeal of the October 2010 order with the Michigan Court of Appeals. In December 2010, the MPSC filed a Motion for Remand with the Court of Appeals. In March 2011, the Court of Appeals denied the Motion for Remand. All briefs have been filed and the case is awaiting scheduling of oral argument.

Wisconsin Fuel Proceedings

Embedded within Wisconsin Electric's base electric rates is an amount to recover fuel costs. The Wisconsin retail fuel rules require the company to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the utility's approved fuel cost plan. The deferred fuel costs are subject to an excess revenues test.

2014 Fuel Cost Plan Request: On July 30, 2013, Wisconsin Electric filed its 2014 fuel cost plan with the PSCW requesting authority to decrease Wisconsin retail electric customers rates approximately $36 million in the form of a fuel credit primarily related to a reduction in delivered coal costs. The plan was approved by the PSCW on December 20, 2013.

2012 Fuel Cost Plan Request: In August 2011, Wisconsin Electric filed a $50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase were projected higher coal, coal transportation and purchased power costs. In January 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE.

In November 2000, Wisconsin Electric filed a complaint against the DOE in the Court of Federal Claims for DOE's failure to remove used nuclear fuel from Point Beach Nuclear Power Plant, which Wisconsin Electric owned until September 2007. We negotiated a settlement with the DOE for $45.5 million, which we received in the first quarter of 2011. This amount, net of costs incurred, was returned to customers.

Other Utility Rate Matters

Oak Creek Air Quality Control System: In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008. In March 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. In September 2012, the equipment for units 7 and 8 was placed into commercial operation. The final cost of completing this project was approximately $740 million ($900 million including AFUDC).

Electric Transmission Cost Recovery: Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in Wisconsin. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed us to use escrow accounting whereby we deferred transmission costs that exceeded amounts embedded in our rates. We were allowed to earn a return on the unrecovered transmission costs we deferred at our weighted-average cost of capital. As of December 31, 2013, we had $126.8 million of unrecovered transmission costs related to prior deferrals that are not subject to escrow accounting because our 2008 and 2010 PSCW rate orders provided for recovery of these costs. In the 2013 Wisconsin Rate Case, the PSCW reauthorized escrow accounting for future transmission costs and we are allowed to accrue these costs on a net of tax basis at the short-term debt rate.

Gas Cost Recovery Mechanism: Our natural gas operations operate under GCRMs as approved by the PSCW. Generally, the GCRMs allow for a dollar for dollar recovery of gas costs. The GCRMs use a modified one for one method that measures commodity purchase costs against a monthly benchmark which includes a 2% tolerance. Costs in excess of this monthly benchmark are subject to additional review by the PSCW before they can be passed through to our customers.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin revised the requirements for renewable energy generation by enacting 2005 Wisconsin Act 141 (Act 141). Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003. A utility's renewable energy percentage is equal to the amount of its total retail energy sales that are provided by renewable sources. Wisconsin Electric's baseline renewable energy percentage is 2.27%. Under Act 141, Wisconsin Electric could not decrease its renewable energy percentage for the years 2006-2009, and for the years 2010-2014, it must increase its renewable energy percentage at least two percentage points to a level of 4.27%. As of December 31, 2013, we are in compliance with the Wisconsin renewable energy percentage of 4.27%. Act 141 further requires that for the year 2015 and beyond, the renewable energy percentage must increase at least six percentage points above the baseline to a level of 8.27%. Act 141 established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. To comply with increasing requirements, Wisconsin Electric has constructed and contracted for several hundred megawatts of wind generation and constructed a 50 MW biomass facility at Domtar Corporation's Rothschild, Wisconsin paper mill site that went into commercial operation on November 8, 2013. Wood waste and wood shavings are used to produce renewable electricity and will also support Domtar's sustainable papermaking operations. The final cost of completing this project was $269.0 million, excluding AFUDC. We also own four wind sites, consisting of 200 turbines with an installed capacity of 338 MW and a dependable capability of 66 MW.

We expect to be in compliance with Act 141's 2015 standard, and have entered into agreements for renewable energy credits which should allow us to remain in compliance with Act 141 through 2022. If market conditions are favorable, we may purchase more renewable energy credits.

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would result in unreasonable rate increases or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities. Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility may not be ordered to achieve additional energy conservation or efficiency.

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the Wisconsin Department of Administration back to the PSCW and/or contracted third parties. In addition, Act 141 required that 1.2% of utilities' annual operating revenues be used to fund these programs in 2013. The funding required by Act 141 for 2014 is also 1.2% of annual operating revenues.

Public Act 295 enacted in Michigan requires 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. Public Act 295 specifically calls for current recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

Western Gas Lateral: We are projecting the need for additional capacity for our natural gas distribution network in the western part of Wisconsin to address reliability and meet customer demand. We filed an application with the PSCW seeking approval to construct a new natural gas lateral on March 28, 2013. The anticipated cost of the initial phase of this project is approximately $150 million to $170 million, excluding AFUDC.

ELECTRIC SYSTEM RELIABILITY

We continue to upgrade our electric distribution system, including substations, transformers and lines. We had adequate capacity to meet the MISO calculated planning reserve margin during 2013 and 2012. All of our generating plants performed as expected during the warmest periods of the summer and all power purchase commitments under firm contract were received. During this period, public appeals for conservation were not required and we did not interrupt or curtail service to non-firm customers who participate in load management programs. We expect to have adequate capacity to meet the planning reserve margin requirements during 2014. However, extremely hot weather, unexpected equipment failure or unavailability across the 15-state MISO market footprint could require us to call upon load management procedures.

ENVIRONMENTAL MATTERS

Overview

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to current and future regulation of: (1) air emissions such as Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), fine particulates, mercury and greenhouse gas emissions; (2) water discharges; (3) disposal of coal combustion by-products such as fly ash; and (4) remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including: (1) the development of additional sources of renewable electric energy supply; (2) the review of water quality matters such as discharge limits and cooling water requirements and implementing improvements to our cooling water intake systems as needed; (3) the addition of emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (4) the conversion of the fuel source for Valley Power Plant (VAPP) from coal to natural gas; (5) the beneficial use of ash and other solid products from coal-fired generating units; and (6) the clean-up of former manufactured gas plant sites.

Air Quality

EPA - Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the United States Environmental Protection Agency (EPA), in which it agreed to significantly reduce air emissions from its coal-fired generating facilities. In July 2003, the Consent Decree was amended to include the state of Michigan, and in October 2007, the U.S. District Court for the Eastern District of Wisconsin approved and entered the amended Consent Decree. The Consent Decree was further amended in January 2012 to change the point of air monitoring at the Oak Creek Power Plant to accommodate the AQCS that began service in 2012. In order to achieve the reductions agreed to in the Consent Decree, over the past 10 years we have installed new pollution control equipment, including the Oak Creek AQCS, upgraded existing equipment and retired certain older coal units at a cost of approximately $1.2 billion. We do not expect future costs to have a material impact on our consolidated financial statements.

National Ambient Air Quality Standards (NAAQS)

8-hour Ozone Standards: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 1997 8-hour ozone ambient air quality standard. The EPA has since redesignated all of these counties to attainment. In 2008, the EPA issued an additional, more stringent 8-hour ozone standard, and made final attainment designations for this revised standard in 2012. In April 2012 and May 2012, the EPA designated Sheboygan County and the eastern portion of Kenosha County, respectively, as 2008 8-hour ozone standard non-attainment areas. The net result of all of these actions is that construction permitting for all of our Wisconsin power plants, except the Pleasant Prairie Power Plant, is expected to be subject to less stringent permitting requirements. In addition, modifications to these facilities should no longer be required to obtain emission offsets. The Pleasant Prairie Power Plant will continue to be subject to more stringent permitting requirements and offset provisions.

In January 2010, the EPA announced its decision to further lower the 2008 8-hour ozone standard. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard. In January 2014, environmental groups petitioned the U.S. District Court for the Northern District of California to order the EPA to propose a new ozone standard by the end of 2014 and to finalize the standard by October 2015. We expect that the EPA could lower the current 8-hour ozone standard from its current level.

Fine Particulate Standard: In 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the daily standard for $PM_{2.5}$. In April 2012, the EPA proposed to determine that these three counties meet the Fine Particulate Matter ($PM_{2.5}$) standard, and proposed to suspend the requirement that the state submit a State Implementation Plan (SIP) including reasonably available control technology (RACT) regulations. In December 2012, the EPA re-proposed this determination along with further clarification of its authority to suspend RACT and other SIP requirements. Until the EPA finalizes this action and redesignates the three counties to attainment, our generating facilities in the non-attainment counties will continue to be subject to more stringent construction permitting requirements and emission offset provisions. Also in December 2012, the EPA issued a revised and more stringent annual $PM_{2.5}$ standard. Current monitored air quality data indicates that all areas of Wisconsin and Michigan's Upper Peninsula meet the revised standard. Although we do not expect the lower standard to impose any additional requirements on our operations, until the EPA develops a rule or guidance that dictates implementation of the new standard, we are unable to predict how these actions may affect any future construction permitting activities.

Sulfur Dioxide Standard: In June 2010, the EPA issued new hourly SO_2 NAAQS that became effective in August 2010. This standard represented a significant change from the previous SO_2 standard. The implementation guidance for the new standard, among other things, required attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data. The EPA has since advised that it is revisiting this implementation guidance. The EPA issued two technical assistance documents for comment in 2013, and expects to issue a rule in 2014 that will establish requirements for characterizing SO_2 air quality in priority areas.

Various parties have submitted judicial and administrative challenges to this rule, and litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging, among other things, the stringency of the standards and the EPA's plans to require attainment designations to be based on modeling.

If the new standard remains in place, we do not believe that we will need to make any significant additional expenditures at the majority of our generating units because of prior investments in pollution control equipment. However, if the new standard does remain in place we believe that additional environmental controls will be required at Presque Isle Power Plant (PIPP) located in the Upper Peninsula of Michigan.

In November of 2012, we entered into a joint venture agreement with Wolverine Power Supply Cooperative, Inc. (Wolverine) whereby Wolverine would pay for the installation of the air quality control systems at PIPP and receive a minority undivided ownership interest in the plant in return. However, in light of the loss of retail electric customers in Michigan due to that state’s alternative electric supplier program (see Restructuring in Michigan under Industry Restructuring and Competition), we re-evaluated options related to the ownership and operation of PIPP including different alternatives for the joint venture with Wolverine. Ultimately, in December 2013, Wisconsin Electric and Wolverine decided to terminate the joint venture. We are currently evaluating options for the long-term future of PIPP, including the potential sale of the plant. At the same time, we are analyzing several environmental compliance options at PIPP.

The new standard may also require us to make modifications at some of our smaller generation units.

Nitrogen Dioxide Standard: In January 2010, the EPA announced a new hourly Nitrogen Dioxide standard, which became effective in April 2010. We are unable to predict the impact on the operation of our generation facilities until final attainment designations are made and until any potential additional rules are adopted.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final Mercury and Air Toxics Standards (MATS) rule, which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. We currently anticipate that only PIPP will require modifications, and are currently evaluating several available options for PIPP to comply with MATS. In April 2013, we received a one year MATS compliance extension through April 16, 2016 from the Michigan Department of Environmental Quality (MDEQ).

In January 2013, the EPA issued the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Industrial Boiler MACT Rule). The Industrial Boiler MACT rule imposes stringent limitations on numerous hazardous air pollutants from large boilers that do not meet the definition of electric generating units. The compliance date set forth in the rule is January 31, 2016, but a one year extension of that deadline may be available where emission controls cannot be installed and operational by the compliance date. Along with some smaller gas fired boilers in our fleet, the boilers at the Milwaukee County Power Plant (MCPP) are subject to this rule. We are currently evaluating compliance options for the three coal fired boilers at MCPP.

Cross-State Air Pollution Rule: In August 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of NO_x and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation plan. In February 2012, the EPA issued final technical revisions to the rule and issued a draft final rule which together delay the implementation date for certain penalty provisions that could potentially impact the PIPP and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with technical revisions to the rule by the EPA, PIPP may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR, keeping the CAIR in effect. The EPA successfully petitioned the United States Supreme Court, who heard the case in December 2013. A decision is expected by June 2014.

Wisconsin and Michigan Mercury Rules: Both Wisconsin and Michigan have mercury rules that require a 90% reduction of mercury. We have plans in place to comply with those requirements and the costs of these plans are incorporated in our capital and operation and maintenance costs.

Clean Air Visibility Rule: The EPA issued the Clean Air Visibility Rule in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units and how BART will be addressed in the 28 states subject to the EPA's CAIR. The pollutants from power plants that reduce visibility include $PM_{2.5}$ or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia.

In June 2012, the EPA promulgated a Federal Implementation Plan that approves reliance on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2. In December 2012, the EPA approved the remainder of Michigan's regional haze SIP.

In August 2012, the EPA approved Wisconsin's regional haze SIP, which also relies on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2.

Because of the court decision to vacate CSAPR and subsequent appeals, we will not be able to determine final regional haze requirements for NO_x and SO_2 at our facilities until the United States Supreme Court issues its decision and any subsequent rulemaking activities that may be required as a result of that decision have been finalized.

Climate Change: We continue to take measures to reduce our emissions of greenhouse gases. We support flexible, market-based strategies to curb greenhouse gas emissions, including emissions trading, joint implementation projects and credit for early actions. We support an approach that encourages technology development and transfer and includes all sectors of the economy and all significant global emitters. We have taken, and continue to take, several steps to reduce our emissions of greenhouse gases, including:

- Repowered the Port Washington Power Plant from coal to natural gas-fired combined cycle units.
- Added coal-fired units as part of the Oak Creek expansion that are the most thermally efficient coal units in our system.
- Increased our investment in energy efficiency and conservation.
- Added renewable capacity.
- Planning to convert the fuel source at the VAPP from coal to natural gas.
- Retired coal units 1-4 at PIPP.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The regulation of greenhouse gas emissions continues to be a top priority for the President's administration. In June 2013, the President issued a presidential memorandum instructing the EPA to, among other things, issue rules pertaining to greenhouse gas emissions from both new and existing power plants.

The EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the Clean Air Act (CAA). On September 20, 2013, the EPA withdrew its 2012 proposed New Source Performance Standards greenhouse gas emissions rule, and issued new proposed rules with greenhouse gas limits for new fossil fueled power plants. The rule would not apply to certain natural gas fueled peaking plants, biomass units or oil fueled stationary combustion turbines. Based upon currently available technology and the emission limits in the proposed rule, we believe that this rule, if promulgated, would effectively prohibit new conventional coal-fired power plants.

With respect to existing generating units, the EPA has indicated that it intends to issue a proposed rule in June 2014, a final rule by June 2015 and require SIPs to be submitted by June 30, 2016. Any such regulations may impact how we operate our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition.

We are required to report our Carbon Dioxide (CO_2) equivalent emissions from our electric generating facilities to the EPA under its Mandatory Reporting of Greenhouse Gases rule. For 2012, we reported CO_2 equivalent emissions of approximately 18.1 million metric tonnes to the EPA, compared with approximately 22.4 million metric tonnes for 2011. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 21.9 million metric tonnes to the EPA for 2013. The level of CO_2 and other greenhouse gas emissions vary from year to year and are dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed and how our units are dispatched by MISO.

We are also required to report CO_2 amounts related to the natural gas our gas utility distributes and sells. For 2012, we reported approximately 8.4 million metric tonnes of CO_2 to the EPA related to our distribution and sale of natural gas, compared with approximately 9.5 million metric tonnes for 2011. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 emissions of approximately 10.2 million metric tonnes to the EPA for 2013.

Valley Power Plant Conversion: In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas. We currently expect the cost of this conversion to be between $65 million and $70 million, excluding AFUDC, and anticipate that the conversion will be completed by the end of 2015 or early 2016. We filed for a Certificate of Authority from the PSCW on April 26, 2013, and received preliminary approval on January 30, 2014. We expect to receive a final written order by the end of the first quarter. The construction air permit for the gas conversion was issued by the Wisconsin Department of Natural Resources (WDNR) on November 11, 2013.

In June 2012, we received approval from the PSCW to replace and upgrade the Lincoln Arthur natural gas main, which has the capability to accommodate the increased natural gas required for the conversion of VAPP to natural gas. Construction began on the Lincoln Arthur natural gas main in March 2013. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Water Quality

Clean Water Act: Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The EPA finalized rules for new facilities (Phase I) in 2001. Final rules for cooling water intake systems at existing facilities

(Phase II) were promulgated in 2004. However, as a result of litigation, the EPA withdrew the Phase II rule in July 2007 and advised states to use their best professional judgment in making BTA decisions while the rule remains suspended.

The EPA proposed a new Phase II rule in 2011; however, the promulgation of the final rule was delayed and is expected to occur by April 2014. Once the rule is final, we expect that it will apply to all of our existing generating facilities with cooling water intake structures other than the Oak Creek expansion, which was permitted under the Phase I rules.

The proposed rule would create an impingement mortality reduction standard for all existing facilities. One proposed approach would allow a facility owner to satisfy the BTA requirement with respect to impingement mortality reduction if it demonstrates that its cooling water intake system has a maximum intake velocity of no more than 0.5 feet per second. Oak Creek Power Plant Units 5-8, Pleasant Prairie and Port Washington Generating Station all employ technologies that have a cooling water intake withdrawal velocity of less than 0.5 feet per second. We are still evaluating impingement mortality reduction compliance options for the PIPP and VAPP.

The EPA has proposed that the BTA for entrainment mortality reduction be determined on a case-by-case basis. Therefore, permitting agencies would be required to determine BTA with respect to entrainment on a site-specific basis taking into consideration several factors. Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet this proposed requirement.

Depending on the final requirements of the Phase II rule, we may need to modify the cooling water intake systems at some of our facilities. However, we are not able to make a determination until after the Phase II rule is final.

In December, 2012, the WDNR issued a new Wisconsin Pollutant Discharge Elimination System (WPDES) permit for VAPP that became effective on January 1, 2013. The new permit includes significant new immediate and long-term permit requirements. Effluent toxicity testing and monitoring for additional parameters (phosphorous, mercury and ammonia-nitrogen), and a new heat addition limit from the cooling water discharges all took effect immediately. Longer term compliance requirements include thermal discharge studies, phosphorous evaluation and feasibility for reduction, mercury minimization planning, and redesign of the cooling water intakes to minimize impingement impacts to aquatic organisms.

Steam Electric Effluent Guidelines: These guidelines regulate waste water discharges from our power plant processes. In June 2013, the EPA issued a proposed rule for comment to modify these guidelines. We submitted comments primarily addressing potential effects to our wastewater treatment facilities and coal combustion residuals effluent management activities. The rules are expected to be finalized by May 2014. After promulgation of the final rules, the WDNR and MDEQ will need to modify state rules accordingly and then incorporate new requirements into our facility permits. The rule compliance deadline is as soon as possible after July 1, 2017 with full compliance expected by July 1, 2022. We already meet many of the proposed requirements defined by the EPA, and as a result believe we will be well positioned to comply with the proposed guidelines. There are several available options outlined in the proposed rule. The amount of additional costs we may need to incur to comply with the new guidelines, if any, will depend on which option(s) the EPA selects to incorporate into the final guidelines. Until the rules are finalized, we are unable to determine the impact on our facilities.

Land Quality

Proposed New Coal Combustion Products Regulation: We currently have a program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which minimizes the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. In 2010, the EPA issued draft rules for public comment proposing two alternative rules for regulating coal combustion products, one of which would classify the materials as hazardous waste. We anticipate that the EPA could take action on a final rule by the end of 2014. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program.

If coal combustion products are classified as hazardous waste and we terminate our coal combustion products utilization program, we could be required to dispose of the coal combustion products at a significant cost to the Company, which could adversely impact our results of operations and financial condition.

In addition, the EPA finalized the Commercial and Industrial Solid Waste Incineration Units rule under the CAA, as well as the Non-Hazardous Secondary Materials Rule. We received a letter from the EPA in 2013 that allows us to continue ash recovery and reburn as a non-hazardous secondary material based on our processing of the materials prior to reburning as currently allowed under the Secondary Materials Rule.

Manufactured Gas Plant Sites: We continue to voluntarily review and address environmental conditions at a number of former manufactured gas plant sites. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our combustion byproducts. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

LEGAL MATTERS

Stray Voltage: On July 11, 1996, the PSCW issued a final order regarding the stray voltage policies of Wisconsin's investor-owned utilities. The order clarified the definition of stray voltage, affirmed the level at which utility action is required, and placed some of the responsibility for this issue in the hands of the customer. Additionally, the order established a uniform stray voltage tariff which delineates utility responsibility and provides for the recovery of costs associated with unnecessary customer demanded services.

Dairy farmers have made claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. The Wisconsin Supreme Court has rejected the arguments that, if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court has held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation. As a result of these rulings, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW "level of concern." We continue to evaluate various options and strategies to mitigate this risk.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large Regional Transmission Organizations (RTOs), which affect the structure of the wholesale market. To this end, the MISO implemented bid-based markets, the MISO Energy Markets, including the use of Locational Marginal Price (LMP) to value electric transmission congestion and losses. The MISO Energy Markets commenced operation in April 2005 for energy distribution and in January 2009 for operating reserves. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when retail access might be implemented, if at all, in Wisconsin; however, Michigan has adopted retail choice.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. The PSCW has been focused on electric reliability infrastructure issues for the state of Wisconsin in recent years. The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan: Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Sales to these customers, including the mines, totaled 2,173.6 GWh, or 7.6% of our retail electric sales for the year ended December 31, 2012. Previously, the owner of the mines announced that they would shut down the Empire mine by the end of 2014 or beginning of 2015.

We have taken, and will continue to take, multiple steps to mitigate these impacts in 2014 and going forward. In August 2013, we filed a request with MISO to suspend the operation of all five units at PIPP. In October 2013, MISO informed us that the operation of all units is necessary to maintain reliability in the Upper Peninsula of Michigan. On January 30, 2014, we entered into a SSR Agreement with MISO to recover costs for operating and maintaining the units. The Agreement is effective February 1, 2014, has a one year term, and specifies monthly payments to Wisconsin Electric of $4.4 million to cover fixed costs. The Agreement also provides for the payment of our variable costs to operate and maintain the plant. MISO filed the SSR Agreement at FERC on January 31, 2014 and is requesting FERC's approval of this Agreement.

In addition, Wisconsin Electric filed an application with the MPSC requesting authority to defer all fixed production costs that would have been recovered from the customers who switched to an alternative electric supplier. In August 2013, the MPSC issued an order approving the deferral of costs allocable to our remaining Michigan retail customers. In September 2013, we filed a petition for re-hearing with the MPSC requesting reconsideration of its deferral order; however, our request was denied. Our ability to collect the deferred costs will be determined in a subsequent rate proceeding.

Wisconsin Electric files bi-annual retail rate cases in Wisconsin. Our next electric rate case in Wisconsin is for rates to be implemented in January 2015. Wholesale electric rates are set under FERC formula cost-based rates and are adjusted annually. We believe that prudently incurred utility costs will be recovered in future Wisconsin retail rate cases and FERC filings.

We do not expect the loss of these customers to have a material impact on our consolidated results of operations in 2014. Although the financial impact in future periods is uncertain, we expect that successful mitigation efforts and a reasonable regulatory response should make our net financial exposure immaterial.

Electric Transmission, Capacity and Energy Markets

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and an ancillary services market. We previously self-provided both regulation reserves and contingency reserves. In the MISO ancillary services market, we buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market has been able to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market has enabled MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by Load Serving Entities located in the service territories of each MISO transmission owner. FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

We, along with others, have sought rehearing and/or appeal of the FERC's various Revenue Sufficiency Guarantee orders related to the determination that MISO had applied its energy markets tariff correctly in the assessment of the charges. The net effects of any final determination by FERC or the courts are uncertain at this time.

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs). ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2013 through May 31, 2014. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

Beginning June 1, 2013, MISO instituted an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources could be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. Our capacity requirements were fulfilled using our own capacity resources.

Natural Gas Utility Industry

Restructuring in Wisconsin: The PSCW previously instituted generic proceedings to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to deregulate the sale of natural gas in customer segments with workably competitive market choices and has adopted standards for transactions between a utility and its gas marketing affiliates. However, work on deregulation of the gas distribution industry by the PSCW continues to be on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. In May 2013, we began testing various combinations of sub-bituminous coal and bituminous coal to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make any fuel flexibility modifications. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed a petition for a contested case hearing with the WDNR to challenge the issuance of the air construction permit. The WDNR has granted that petition, but a hearing has not yet been scheduled.

***Paris Generating Station Units 1 and 4 Temporary Outage*:** Between 2000 and 2002, we replaced the blades on the four Paris Generating Station (PSGS) combustion turbine generators with blades that were approximately 7% more efficient. Although the work was performed as routine maintenance that we did not believe required a construction permit at the time and the plant has not been operated to use the potential additional capacity, the WDNR has indicated that it now considers this maintenance to be a modification requiring a construction permit. The WDNR issued a Notice of Violation to Wisconsin Electric on January 7, 2013 alleging violations of the new source review rules and certain Wisconsin environmental rules. At the same time, the WDNR also issued an administrative order that prohibits us from operating PSGS Units 1 and 4 until the earlier of: (1) Units 1 and 4 achieve the applicable NO_x emission rates; (2) the Wisconsin regulations are revised so that Units 1 and 4 can achieve the emission limits or are no longer subject to the limits; (3) the alleged modification is resolved through a consent decree; or (4) a court decides that the blade replacement project was not a major modification. We are presently evaluating alternative approaches to return these peaking units to service, and expect Units 1 and 4 to remain out of service until at least the end of the second quarter of 2014. In December 2013, Act 91 was signed into law in Wisconsin, creating a process by which the EPA and WDNR may revise the regulations applicable to Units 1 and 4 and allow those units to restart.

In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order. The WDNR has granted that petition, but a hearing has not yet been scheduled. In addition, in May 2013, the WDNR referred the matter to the Wisconsin Department of Justice for alleged violations of air management statutes and rules. We could be subject to fines and penalties.

PSGS Units 2 and 3 remain available for operation because the turbine blade maintenance on these units occurred prior to a rule change in 2001.

ACCOUNTING DEVELOPMENTS

New Pronouncements: See Note B -- Recent Accounting Pronouncements in the Notes to Consolidated Financial Statements in this report for information on new accounting pronouncements.

Treasury Grant: In December 2013, we filed an application with the United States Treasury for a Section 1603 renewable energy grant related to the construction of our biomass facility in Rothschild, Wisconsin. We recorded a receivable for $82.6 million related to the grant that we expect to receive in the first half of 2014. The PSCW anticipated the recognition of this grant as income when it set rates for the two years beginning January 1, 2013. During 2013, we have provided bill credits to our Wisconsin electric customers which reflects the grant as income. The bill credits also reflect the tax benefits related to the grant. The bill credits will continue in 2014.

During 2013, we recognized the Treasury Grant as income, less the amounts that we have established as a deferred liability. The amount reflected in earnings matched the amount of the bill credits given to customers. The deferred balance reflects the amount of the grant income that we expect to benefit our customers in the future. This accounting reflects the regulatory treatment of the grant.

The PSCW approved escrow accounting treatment for the Treasury Grant. Under escrow accounting, we true-up any differences between the actual grant proceeds received and the grant proceeds passed on to customers in the form of bill credits.

Tangible Property Regulations: During September 2013, the Treasury Department and IRS issued final regulations pertaining to costs incurred to acquire, maintain or improve tangible property. These regulations are generally effective for tax years beginning on or after January 1, 2014. We continue to evaluate what impact, if any, the adoption of the regulations will have on our consolidated financial statements; however, we do not currently expect the impact to be material.

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgments:

Regulatory Accounting: Our utility subsidiaries operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. The actions of our regulators may allow us to defer costs that non-regulated entities would expense and accrue liabilities that non-regulated companies would not. As of December 31, 2013, we had $1,108.5 million in regulatory assets and $879.1 million in regulatory liabilities. In the future, if we move to market based rates, or if the actions of our regulators change, we may conclude that we are unable to follow regulatory accounting. In this situation, we would record the regulatory assets related to unrecognized pension and OPEB costs as a reduction of equity, after tax. The balance of our regulatory assets net of regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of regulatory accounting and have determined that it is currently appropriate to continue following it. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and OPEB: Our reported costs of providing non-contributory defined pension benefits (described in Note N -- Benefits in the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

Changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following table reflects pension plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	$ 5.2
0.5% decrease in expected rate of return on plan assets	$ 6.6

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note N -- Benefits in the Notes to Consolidated Financial Statements). Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan experience including employee demographics (age and compensation levels), our contributions to the plans, earnings on plan assets and health care cost trends. Changes made to the provisions of the plans may also impact current and future OPEB costs. OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the OPEB and post-retirement costs. Our OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased other post-retirement costs in future periods. Similar to accounting for pension plans, the regulators of our utility segment have adopted accounting guidance for compensation related to retirement benefits for rate-making purposes.

The following table reflects OPEB plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

OPEB Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)	
0.5% decrease in discount rate	$	0.7
0.5% decrease in health care cost trend rate in all future years	$	(1.5)
0.5% decrease in expected rate of return on plan assets	$	1.4

Unbilled Revenues: We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2013 of approximately $4.5 billion included accrued utility revenues of $321.1 million as of December 31, 2013.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks in this report, as well as Note L -- Derivative Instruments and Note M -- Fair Value Measurements in the Notes to Consolidated Financial Statements, for information concerning potential market risks to which Wisconsin Energy and its subsidiaries are exposed.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED INCOME STATEMENTS
Year Ended December 31

	2013	2012	2011
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 4,519.0	$ 4,246.4	$ 4,486.4
Operating Expenses			
Fuel and purchased power	1,153.0	1,098.6	1,169.7
Cost of gas sold	674.1	545.8	728.7
Other operation and maintenance	1,155.0	1,116.1	1,256.8
Depreciation and amortization	388.1	364.2	330.2
Property and revenue taxes	116.7	121.4	113.7
Total Operating Expenses	3,486.9	3,246.1	3,599.1
Treasury Grant	48.0	—	—
Operating Income	1,080.1	1,000.3	887.3
Equity in Earnings of Transmission Affiliate	68.5	65.7	62.5
Other Income and Deductions, net	18.8	34.8	62.7
Interest Expense, net	252.1	248.2	235.8
Income from Continuing Operations Before Income Taxes	915.3	852.6	776.7
Income Tax Expense	337.9	306.3	263.9
Income from Continuing Operations	577.4	546.3	512.8
Income from Discontinued Operations, Net of Tax	—	—	13.4
Net Income	$ 577.4	$ 546.3	$ 526.2
Earnings Per Share (Basic)			
Continuing Operations	$ 2.54	$ 2.37	$ 2.20
Discontinued Operations	—	—	0.06
Total Earnings Per Share (Basic)	$ 2.54	$ 2.37	$ 2.26
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.51	$ 2.35	$ 2.18
Discontinued Operations	—	—	0.06
Total Earnings Per Share (Diluted)	$ 2.51	$ 2.35	$ 2.24
Weighted Average Common Shares Outstanding (Millions)			
Basic	227.6	230.2	232.6
Diluted	229.7	232.8	235.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2013	2012
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 14,966.3	$ 14,238.8
Accumulated depreciation	(4,257.1)	(4,036.0)
	10,709.2	10,202.8
Construction work in progress	149.6	315.9
Leased facilities, net	47.8	53.5
Net Property, Plant and Equipment	10,906.6	10,572.2
Investments		
Equity investment in transmission affiliate	402.7	378.3
Other	36.1	35.5
Total Investments	438.8	413.8
Current Assets		
Cash and cash equivalents	26.0	35.6
Accounts receivable, net of allowance for doubtful accounts of $61.0 and $58.0	406.0	285.3
Accrued revenues	321.1	278.1
Materials, supplies and inventories	329.4	360.7
Current deferred tax asset, net	310.0	105.3
Prepayments	145.7	145.5
Other	12.9	62.1
Total Current Assets	1,551.1	1,272.6
Deferred Charges and Other Assets		
Regulatory assets	1,108.5	1,380.3
Goodwill	441.9	441.9
Other	322.5	204.2
Total Deferred Charges and Other Assets	1,872.9	2,026.4
Total Assets	$ 14,769.4	$ 14,285.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

CAPITALIZATION AND LIABILITIES

	2013	2012
	(Millions of Dollars)	
Capitalization		
Common equity	$ 4,233.0	$ 4,135.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,363.2	4,453.8
Total Capitalization	8,626.6	8,619.3
Current Liabilities		
Long-term debt due currently	342.2	412.1
Short-term debt	537.4	394.6
Accounts payable	342.6	368.4
Accrued payroll and benefits	96.9	100.9
Other	177.3	165.4
Total Current Liabilities	1,496.4	1,441.4
Deferred Credits and Other Liabilities		
Regulatory liabilities	879.1	868.4
Deferred income taxes - long-term	2,634.0	2,117.0
Deferred revenue, net	664.2	709.7
Pension and other benefit obligations	173.2	244.0
Other long-term liabilities	295.9	285.2
Total Deferred Credits and Other Liabilities	4,646.4	4,224.3
Commitments and Contingencies (Note Q)		
Total Capitalization and Liabilities	$ 14,769.4	$ 14,285.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31

	2013	2012	2011
	(Millions of Dollars)		
Operating Activities			
Net income	$ 577.4	$ 546.3	$ 526.2
Reconciliation to cash			
Depreciation and amortization	400.2	371.7	336.4
Deferred income taxes and investment tax credits, net	312.7	293.2	430.6
Contributions to qualified benefit plans	—	(100.0)	(277.4)
Change in - Accounts receivable and accrued revenues	(162.9)	38.3	30.1
Inventories	31.3	21.3	(2.9)
Other current assets	2.8	12.1	(20.5)
Accounts payable	(14.8)	43.8	11.8
Accrued income taxes, net	36.6	116.9	(87.4)
Deferred costs, net	(8.7)	9.2	25.9
Other current liabilities	7.2	(14.9)	44.1
Other, net	49.2	(164.0)	(23.5)
Cash Provided by Operating Activities	1,231.0	1,173.9	993.4
Investing Activities			
Capital expenditures	(687.4)	(707.0)	(830.8)
Investment in transmission affiliate	(10.5)	(15.7)	(6.6)
Proceeds from asset sales	2.5	8.7	41.5
Change in restricted cash	2.7	42.8	(37.2)
Cost of removal, net of salvage	(37.8)	(38.3)	(16.9)
Other, net	(15.3)	(20.1)	(42.5)
Cash Used in Investing Activities	(745.8)	(729.6)	(892.5)
Financing Activities			
Exercise of stock options	48.5	49.8	54.4
Purchase of common stock	(223.4)	(153.2)	(193.9)
Dividends paid on common stock	(328.9)	(276.3)	(242.0)
Issuance of long-term debt	251.0	251.8	720.0
Retirement of long-term debt	(397.2)	(20.3)	(466.6)
Change in short-term debt	142.8	(275.3)	12.0
Other, net	12.4	0.7	4.8
Cash Used in Financing Activities	(494.8)	(422.8)	(111.3)
Change in Cash and Cash Equivalents	(9.6)	21.5	(10.4)
Cash and Cash Equivalents at Beginning of Year	35.6	14.1	24.5
Cash and Cash Equivalents at End of Year	$ 26.0	$ 35.6	$ 14.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Total
	(Millions of Dollars)			
Balance - December 31, 2010	$ 2.3	$ 721.5	$ 3,078.3	$ 3,802.1
Net income			526.2	526.2
Common stock cash dividends of $1.04 per share			(242.0)	(242.0)
Exercise of stock options		54.4		54.4
Purchase of common stock		(193.9)		(193.9)
Tax benefit from share based compensation		11.9		11.9
Stock-based compensation and other		4.6		4.6
Balance - December 31, 2011	2.3	598.5	3,362.5	3,963.3
Net income			546.3	546.3
Common stock cash dividends of $1.20 per share			(276.3)	(276.3)
Exercise of stock options		49.8		49.8
Purchase of common stock		(153.2)		(153.2)
Stock-based compensation and other		5.2		5.2
Balance - December 31, 2012	2.3	500.3	3,632.5	4,135.1
Net income			577.4	577.4
Common stock cash dividends of $1.445 per share			(328.9)	(328.9)
Exercise of stock options		48.5		48.5
Purchase of common stock		(223.4)		(223.4)
Tax benefit from share based compensation		18.1		18.1
Stock-based compensation and other		6.2		6.2
Balance - December 31, 2013	$ 2.3	$ 349.7	$ 3,881.0	$ 4,233.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

		2013	2012
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$ 4,233.0	$ 4,135.1
Preferred Stock of Subsidiary (Note I)		30.4	30.4
Long-Term Debt			
Wisconsin Energy Notes (unsecured)	6.20% due 2033	200.0	200.0
	6.25% Junior Notes due 2067	500.0	500.0
Wisconsin Electric Debentures (unsecured)	4.50% due 2013	—	300.0
	6.00% due 2014	300.0	300.0
	6.25% due 2015	250.0	250.0
	1.70% due 2018	250.0	—
	4.25% due 2019	250.0	250.0
	2.95% due 2021	300.0	300.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.70% due 2036	300.0	300.0
	3.65% due 2042	250.0	250.0
	6-7/8% due 2095	100.0	100.0
Wisconsin Electric Notes (unsecured)	0.504% variable rate due 2016 (a)	67.0	67.0
	0.504% variable rate due 2030 (a)	80.0	80.0
	Variable rate notes	(147.0)	(147.0)
Wisconsin Gas Debentures (unsecured)	6.60% due 2013	—	45.0
	5.20% due 2015	125.0	125.0
	5.90% due 2035	90.0	90.0
We Power Subsidiary Notes (secured, nonrecourse)	4.91% due 2013-2030 (b)	122.1	126.7
	5.209% due 2013-2030 (c)	231.5	238.6
	4.673% due 2013-2031 (c)	190.9	196.7
	6.00% due 2013-2033 (b)	138.4	142.1
	6.09% due 2030-2040 (c)	275.0	275.0
	5.848% due 2031-2041 (c)	215.0	215.0
WECC Notes (unsecured)	6.51% due 2013	—	30.0
	6.94% due 2028	50.0	50.0
Other Notes (secured, nonrecourse)	6.00% due 2021	1.8	1.8
	4.81% effective rate due 2030	2.0	2.0
Obligations under capital leases		104.3	120.0
Unamortized discount, net and other		(25.6)	(27.0)
Long-term debt due currently		(342.2)	(412.1)
Total Long-Term Debt		4,363.2	4,453.8
Total Capitalization		$ 8,626.6	$ 8,619.3

(a) Variable interest rate as of December 31, 2013.

(b) Senior notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric related to PWGS 1 and 2.

(c) Senior notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 1 and 2.

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: Our consolidated financial statements include the accounts of Wisconsin Energy Corporation (Wisconsin Energy, the Company, our, we or us), a diversified holding company, as well as our subsidiaries in the following reportable segments:

- ***Utility Energy Segment*** -- Consisting of Wisconsin Electric and Wisconsin Gas, engaged primarily in the generation of electricity and the distribution of electricity and natural gas; and

- ***Non-Utility Energy Segment*** -- Consisting primarily of We Power, engaged principally in the ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Our Corporate and Other segment includes Wispark, which develops and invests in real estate. We have also eliminated all intercompany transactions from the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications and Adjustments: As of December 31, 2013, we have presented the tax effect of net operating loss carryforwards within current deferred tax assets, net on the consolidated balance sheets. As of December 31, 2012, $59.0 million representing the tax effect of net operating loss carryforwards were included in income taxes receivable, which is a line item that has now been condensed within other current assets on the consolidated balance sheets. This $59.0 million amount has been adjusted in the consolidated balance sheets as of December 31, 2012 to conform to the December 31, 2013 presentation, and conforming changes have been made in the consolidated statements of cash flows and in the notes to the consolidated financial statements. For additional information related to our deferred tax assets, see Note G.

In addition, we have adjusted the presentation of regulatory assets and liabilities to present amounts as noncurrent assets and liabilities on the consolidated balance sheets. Prior period amounts recorded within other current assets and liabilities have been reclassified to conform to the current presentation. For additional information related to regulatory assets and liabilities, see Note C.

Revenues: We recognize energy revenues on the accrual basis and include estimated amounts for services rendered but not billed.

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules in Wisconsin allow us to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the approved fuel cost plan. The deferred under-collected amounts are subject to an excess revenues test.

Our retail gas rates include monthly adjustments which permit the recovery or refund of actual purchased gas costs. We defer any difference between actual gas costs incurred (adjusted for a sharing mechanism) and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

We recognize We Power revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease.

Accounting for MISO Energy Transactions: The MISO Energy Markets operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour.

Other Income and Deductions, Net: We recorded the following items in Other Income and Deductions, net for the years ended December 31:

Other Income and Deductions, net	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Equity	$ 18.3	$ 35.3	$ 59.4
Other, net	0.5	(0.5)	3.3
Total Other Income and Deductions, net	$ 18.8	$ 34.8	$ 62.7

Property and Depreciation: We record property, plant and equipment at cost. Cost includes material, labor, overheads and capitalized interest. Utility property also includes AFUDC - Equity. Additions to and significant replacements of property are charged to property, plant and equipment at cost; minor items are charged to maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We recorded the following property in service by segment as of December 31:

Property In Service	2013	2012
	(Millions of Dollars)	
Utility Energy	$ 11,779.8	$ 11,080.9
Non-Utility Energy	3,091.3	3,068.5
Other	95.2	89.4
Total	$ 14,966.3	$ 14,238.8

Our utility depreciation rates are certified by the PSCW and MPSC and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 2.9% in 2013 and 2012, and 2.8% in 2011.

We depreciate our We Power assets over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2, and 10 to 55 years for OC 1 and OC 2.

Our regulated utilities collect in their rates amounts representing future removal costs for many assets that do not have an associated Asset Retirement Obligation (ARO). We record a regulatory liability on our balance sheet for the estimated amounts we have collected in rates for future removal costs less amounts we have spent in removal activities. This regulatory liability was $724.5 million as of December 31, 2013 and $725.0 million as of December 31, 2012.

We recorded the following Construction Work in Progress (CWIP) by segment as of December 31:

CWIP	2013	2012
	(Millions of Dollars)	
Utility Energy	$ 132.7	$ 298.2
Non-Utility Energy	16.5	13.3
Other	0.4	4.4
Total	$ 149.6	$ 315.9

Allowance For Funds Used During Construction - Regulated: AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC - Debt) used during plant construction, and a return on stockholders' capital (AFUDC - Equity) used for construction purposes. AFUDC - Debt is recorded as a reduction of interest expense, and AFUDC - Equity is recorded in Other Income and Deductions, net.

Our regulated utility segment recorded the following AFUDC for the years ended December 31:

	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Debt	$ 7.7	$ 14.7	$ 24.7
AFUDC - Equity	$ 18.3	$ 35.3	$ 59.4

Capitalized Interest and Carrying Costs - Non-Regulated Energy: As part of the construction of the PTF electric generating units, we capitalized interest during construction. As allowed under the lease agreements, we were able to collect the carrying costs during the construction of the PTF generating units from our utility customers. The carrying costs that we collected during construction have been recorded as deferred revenue on our balance sheet and we are amortizing the deferred carrying costs to revenue over the individual lease terms.

Earnings per Common Share: We compute basic earnings per common share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per common share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. All stock options outstanding during 2013, 2012 and 2011 were included in the computation of diluted earnings per share. Anti-dilutive shares are excluded from the calculation.

Materials, Supplies and Inventories: Our inventory as of December 31 consists of:

Materials, Supplies and Inventories	2013	2012
	(Millions of Dollars)	
Fossil Fuel	$ 117.7	$ 165.5
Materials and Supplies	133.9	121.9
Natural Gas in Storage	77.8	73.3
Total	$ 329.4	$ 360.7

Substantially all fossil fuel, materials and supplies, and natural gas in storage inventories are recorded using the weighted-average cost method of accounting.

Regulatory Accounting: The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and expensed in the periods when they are reflected in rates. We defer regulatory assets pursuant to specific or generic orders issued by our regulators. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. In general, regulatory assets are recovered in a period between one to eight years. For further information, see Note C.

Asset Retirement Obligations: We record a liability for a legal ARO in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount or incur a gain or loss. As it relates to our regulated operations, we apply regulatory accounting guidance and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs. For further information, see Note E.

Derivative Financial Instruments: We have derivative physical and financial instruments which we report at fair value. For further information, see Note L.

Cash and Cash Equivalents: Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

Margin Accounts: Cash deposited in brokerage accounts for margin requirements is recorded in Other Current Assets on our Consolidated Balance Sheets.

Goodwill: Goodwill reflects the cost of an acquisition in excess of the fair values assigned to identifiable net assets acquired. As of December 31, 2013 and 2012, we had $441.9 million of goodwill recorded at the utility energy segment, which related to our acquisition of Wisconsin Gas in 2000.

Goodwill is not subject to amortization. However, it is subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are to be reflected in operating expense. Fair value is assessed by considering future discounted cash flows, a comparison of fair value based on public company trading multiples, and merger and acquisition transaction multiples for similar companies. This evaluation utilizes the information available under the circumstances, including reasonable and supportable assumptions and projections. We perform our annual impairment test as of August 31. There was no impairment to the recorded goodwill balance as of our annual 2013 impairment test date.

Impairment or Disposal of Long Lived Assets: We carry property, equipment and goodwill related to businesses held for sale at the lower of cost or estimated fair value less cost to sell. As of December 31, 2013, we had no assets classified as Held for Sale. Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable from the use and eventual disposition of the asset based on the remaining useful life. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method of accounting. We had a total ownership interest of approximately 26.2% in ATC as of December 31, 2013 and 2012. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note P.

Income Taxes: We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations. For further information, see Note G.

We recognize interest and penalties accrued related to unrecognized tax benefits in Income Taxes in our Consolidated Income Statements, as well as Regulatory Assets or Regulatory Liabilities in our Consolidated Balance Sheets.

We collect sales and use taxes from our customers and remit these taxes to governmental authorities. These taxes are recorded in our Consolidated Income Statements on a net basis.

Stock Options: We estimate the fair value of stock options using the binomial pricing model. We report unearned stock-based compensation associated with non-vested restricted stock and performance share awards activity within Other Paid in Capital in our Consolidated Statements of Common Equity. We report excess tax benefits as a financing cash inflow. Historically, all stock options have been granted with an exercise price equal to the fair market value of the common stock on the date of grant and expire no later than 10 years from grant date. For a discussion of the impacts to our Consolidated Financial Statements, see Note H.

The fair value of our stock options was calculated using a binomial option-pricing model using the following weighted-average assumptions:

	2013	2012	2011
Risk-free interest rate	0.1% - 1.9%	0.1% - 2.0%	0.2% - 3.4%
Dividend yield	3.7%	3.9%	3.9%
Expected volatility	18.0%	19.0%	19.0%
Expected life (years)	5.9	5.9	5.5
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$3.45	$3.34	$3.17

Treasury Grant: In December 2013, we filed an application with the United States Treasury for a Section 1603 renewable energy grant related to the construction of our biomass facility in Rothschild, Wisconsin. The PSCW anticipated the recognition of this grant as income when it set rates for the two years beginning January 1, 2013. We provided bill credits to our customers in 2013, and this will continue into 2014. As of December 31, 2013, $48.0 million was recognized as income, which reflects the amount that was returned to customers in the form of bill credits during the year. We recorded an $82.6 million receivable, and deferred the balance that we expect to benefit our customers in the future. The accounting reflects the regulatory treatment of the grant.

The PSCW approved escrow accounting treatment for the Treasury Grant. Under escrow accounting, we true-up any differences between the actual grant proceeds received and the grant proceeds passed on to customers in the form of bill credits.

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Offsetting Assets and Liabilities: In January 2013, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2013-01, Disclosures about Offsetting Assets and Liabilities. The guidance requires enhanced disclosures about derivatives. Both gross and net information related to eligible transactions is required under the guidance. This guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013, and must be applied retrospectively. We adopted this guidance on January 1, 2013, and applied it retrospectively. The adoption and retrospective application of this guidance did not have any material impact on our financial statements. See Note L -- Derivative Instruments for the enhanced disclosures.

C -- REGULATORY ASSETS AND LIABILITIES

Our primary regulator, the PSCW, considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon orders or correspondence with our regulators. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2013, we had $10.1 million of regulatory assets not earning a return and $82.7 million of regulatory assets earning a return based on short-term interest rates.

In December 2012, the PSCW issued a rate order effective January 1, 2013 that, among other things, reaffirmed our accounting for the regulatory assets and liabilities identified below.

Our regulatory assets and liabilities as of December 31 consist of:

	2013	2012
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$ 537.6	$ 731.5
Deferred income tax related	169.5	176.5
Escrowed electric transmission costs	126.8	114.1
Escrowed conservation	66.9	73.5
Deferred plant related -- capital lease	56.5	66.6
Deferred environmental costs	47.0	47.4
Other, net	104.2	170.7
Total regulatory assets	$ 1,108.5	$ 1,380.3
Regulatory Liabilities		
Deferred cost of removal obligations	$ 724.5	$ 725.0
Escrowed bad debt costs	64.6	81.1
Other, net	90.0	62.2
Total regulatory liabilities	$ 879.1	$ 868.3

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

The following table summarizes the net impacts of the discontinued operations on our earnings for the years ended December 31:

	2013	2012	2011
		(Millions of Dollars)	
Income from Continuing Operations	$ 577.4	$ 546.3	$ 512.8
Income from Discontinued other operations, net of tax (a)	—	—	13.4
Net Income	$ 577.4	$ 546.3	$ 526.2

(a) Primarily relates to the favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company (WPL) for our net book value, including working capital, of approximately $38 million. This transaction was treated as a sale of an asset.

E -- ASSET RETIREMENT OBLIGATIONS

AROs have been recorded for asbestos abatement at certain generation and substation facilities, and for obligations associated with the removal and dismantlement of generation facilities. AROs are recorded in other long-term liabilities on the Consolidated Balance Sheets. The following table presents the change in our AROs during 2013 and 2012:

	2013	2012
	(Millions of Dollars)	
Balance as of January 1	$ 44.3	$ 55.5
Liabilities Settled	(4.4)	(14.0)
Accretion	2.4	2.8
Balance as of December 31	$ 42.3	$ 44.3

F -- VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Certain disclosures are required by sponsors, significant interest holders in variable interest entities and potential variable interest entities.

We assess our relationships with potential variable interest entities such as our coal suppliers, natural gas suppliers, coal and gas transporters, and other counterparties in power purchase agreements and joint ventures. In making this assessment, we consider the potential that our contracts or other arrangements provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of the entity, the ability to directly or indirectly make decisions about the entities' activities and other factors.

We have identified a purchased power agreement which represents a variable interest. This agreement is for 236 MW of firm capacity from a gas-fired cogeneration facility and we account for it as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately nine years. We have examined the risks of the entity including operations and maintenance, dispatch, financing, fuel costs and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity and there is no residual guarantee associated with the purchased power agreement.

We have approximately $215.9 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under contracts considered variable interests in 2013, 2012 and 2011 were $50.3 million, $45.8 million and $65.9 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

G -- INCOME TAXES

The following table is a summary of income tax expense for each of the years ended December 31:

Income Taxes	2013	2012	2011
	(Millions of Dollars)		
Current tax expense (benefit)	$ 25.2	$ 13.1	$ (166.7)
Deferred income taxes, net	313.8	294.4	434.8
Investment tax credit, net	(1.1)	(1.2)	(4.2)
Total Income Tax Expense	$ 337.9	$ 306.3	$ 263.9

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable U.S. statutory federal income tax rate to income before income taxes as a result of the following:

	2013		2012		2011	
Income Tax Expense	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	$ 320.3	35.0 %	$ 298.4	35.0 %	$ 271.8	35.0 %
State income taxes net of federal tax benefit	49.0	5.3 %	43.3	5.1 %	40.1	5.2 %
Production tax credits	(16.7)	(1.8)%	(15.9)	(1.9)%	(8.7)	(1.1)%
Treasury Grant	(7.4)	(0.8)%	—	— %	—	— %
AFUDC - Equity	(6.4)	(0.7)%	(12.3)	(1.4)%	(20.8)	(2.7)%
Investment tax credit restored	(1.1)	(0.1)%	(1.2)	(0.1)%	(4.2)	(0.5)%
Domestic production activities deduction	—	— %	(12.6)	(1.5)%	(12.6)	(1.6)%
Other, net	0.2	— %	6.6	0.7 %	(1.7)	(0.3)%
Total Income Tax Expense	$ 337.9	36.9 %	$ 306.3	35.9 %	$ 263.9	34.0 %

The components of deferred income taxes classified as net current assets and net long-term liabilities as of December 31 are as follows:

Deferred Tax Assets	2013	2012
	(Millions of Dollars)	
Current		
Future federal tax benefits	$ 309.7	$ 59.0
Employee benefits and compensation	13.8	14.9
Other	56.0	81.1
Total Current Deferred Tax Assets	379.5	155.0
Non-current		
Deferred revenues	237.0	250.0
Employee benefits and compensation	95.6	97.0
Future federal tax benefits	32.5	334.7
Property-related	28.2	28.3
Construction advances	18.3	22.2
Other	62.9	16.3
Total Non-Current Deferred Tax Assets	474.5	748.5
Total Deferred Tax Assets	$ 854.0	$ 903.5

Deferred Tax Liabilities	2013	2012
	(Millions of Dollars)	
Current		
Prepaid items	$ 69.5	$ 49.7
Total Current Deferred Tax Liabilities	69.5	49.7
Non-current		
Property-related	2,574.4	2,339.4
Employee benefits and compensation	238.5	244.3
Investment in transmission affiliate	169.9	144.9
Deferred transmission costs	50.8	45.7
Other	74.9	91.2
Total Non-current Deferred Tax Liabilities	3,108.5	2,865.5
Total Deferred Tax Liabilities	$ 3,178.0	$ 2,915.2

Consolidated Balance Sheet Presentation	2013	2012
Current Deferred Tax Asset	$ 310.0	$ 105.3
Non-Current Deferred Tax Liability	$ 2,634.0	$ 2,117.0

Consistent with rate-making treatment, deferred taxes are offset in the above table for temporary differences which have related regulatory assets or liabilities.

As of December 31, 2013, we had approximately $810.3 million and $58.6 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $283.6 million and $58.6 million, respectively. As of December 31, 2012, we had approximately $1,007.1 million and $41.2 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $352.5 million and $41.2 million, respectively. The tax credit and net operating loss carryforwards begin to expire in 2029. We anticipate that we will have future taxable income sufficient to utilize these deferred tax assets.

We previously adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2013	2012
	(Millions of Dollars)	
Balance as of January 1	$ 11.3	$ 11.1
Additions for tax positions of prior years	—	10.8
Reductions for tax positions of prior years	(2.9)	(10.6)
Balance as of December 31	$ 8.4	$ 11.3

The amount of unrecognized tax benefits as of December 31, 2013 and 2012 excludes deferred tax assets related to uncertainty in income taxes of $8.4 million and $10.2 million, respectively. As of December 31, 2013, there were no unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations. As of December 31, 2012, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately $1.0 million.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2013, 2012 and 2011, we recognized approximately $0.2 million, $0.2 million and $0.7 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2013 and 2012, we recognized no penalties in the Consolidated Income Statements. For the year ended 2011, we recognized a benefit of $0.3 million in the Consolidated Income Statements related to a reduction of accrued penalties. We had approximately $0.4 million and $0.3 million of interest accrued and no penalties accrued on the Consolidated Balance Sheets as of December 31, 2013 and 2012, respectively.

We do not anticipate any significant increases or decreases in the total amounts of unrecognized tax benefits within the next 12 months.

Our primary tax jurisdictions include the United States and the state of Wisconsin. Currently, the tax years of 2011 through 2013 are subject to Federal examination, and the tax years 2009 through 2013 are subject to examination by the state of Wisconsin.

H -- COMMON EQUITY

As of December 31, 2013 and 2012, we had 325,000,000 shares of common stock authorized under our charter, of which 225,962,959 and 229,039,456 common shares, respectively, were outstanding. All share-based compensation is currently fulfilled by purchases on the open market by our independent agents and do not dilute shareholders' ownership.

Share-Based Compensation Plans: We have a plan that was approved by stockholders that enables us to provide a long-term incentive through equity interests in Wisconsin Energy to outside directors, selected officers and key employees of the Company. The plan provides for the granting of stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in common stock, cash or a combination thereof. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to the terms of outstanding stock options during the period.

The following table summarizes recorded pre-tax share-based compensation expense and the related tax benefit for share-based awards made to our employees and directors as of December 31:

	2013	2012	2011
		(Millions of Dollars)	
Performance units	$ 12.7	$ 16.3	$ 24.1
Stock options	3.9	2.7	2.6
Restricted stock	2.4	3.0	1.8
Share-based compensation expense	$ 19.0	$ 22.0	$ 28.5
Related Tax Benefit	$ 7.6	$ 8.8	$ 11.4

Stock Options: The exercise price of a stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. Option grants consist of non-qualified stock options that vest on a cliff-basis after a three year period. Options expire no later than 10 years from the date of grant. For further information regarding stock-based compensation and the valuation of our stock options, see Note A.

We expect that substantially all of the outstanding options as of December 31, 2013 will be exercised.

The following is a summary of our stock option activity during 2013:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2013	8,919,669	$ 23.86		
Granted	1,418,560	$ 37.46		
Exercised	(2,238,489)	$ 21.67		
Forfeited	(10,030)	$ 35.37		
Outstanding as of December 31, 2013	8,089,710	$ 26.84	5.4	$ 117.3
Exercisable as of December 31, 2013	5,708,920	$ 23.16	4.1	$ 103.8

In January 2014, the Compensation Committee of the Board of Directors (Compensation Committee) awarded 899,500 non-qualified stock options with an exercise price of $41.03 to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2013, 2012 and 2011 was $44.5 million, $47.5 million and $36.1 million, respectively. Cash received from options exercised during the years ended December 31, 2013, 2012 and 2011 was $48.5 million, $49.8 million and $54.4 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $17.8 million, zero and $14.3 million, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2013:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$16.72 to $21.11	2,128,370	$ 20.34	3.9	2,128,370	$ 20.34	3.9
$23.88 to $29.35	3,689,900	$ 24.65	4.2	3,382,630	$ 24.23	4.0
$34.88 to $37.46	2,271,440	$ 36.48	8.6	197,920	$ 35.19	8.1
	8,089,710	$ 26.84	5.4	5,708,920	$ 23.16	4.1

The following table summarizes information about our non-vested options during 2013:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-Vested as of January 1, 2013	1,702,275	$ 3.31
Granted	1,418,560	$ 3.45
Vested	(730,015)	$ 3.34
Forfeited	(10,030)	$ 3.37
Non-Vested as of December 31, 2013	2,380,790	$ 3.38

As of December 31, 2013, total compensation costs related to non-vested stock options not yet recognized was approximately $2.0 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

Restricted Shares: The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during 2013:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2013	188,222	
Granted	74,290	$ 37.65
Released	(97,973)	$ 26.65
Forfeited	(13,841)	$ 33.35
Outstanding as of December 31, 2013	150,698	

In January 2014, the Compensation Committee awarded 71,504 restricted shares to our directors, officers and other key employees under its normal schedule of awarding long-term incentive compensation. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients also have voting rights and are entitled to dividends in the same manner as other shareholders.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was $4.0 million, $3.5 million and $2.5 million for the years ended December 31, 2013, 2012, and 2011, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was $1.3 million, zero and $0.8 million, respectively.

As of December 31, 2013, total compensation cost related to restricted stock not yet recognized was approximately $2.6 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Performance Units: In January 2013, 2012 and 2011, the Compensation Committee awarded 239,120, 346,570 and 435,690 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year performance period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2013, 2012 and 2011 vested and were settled during the first quarter of 2014, 2013 and 2012, and had a total intrinsic value of $14.8 million, $19.3 million and $26.7 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately $5.3 million, $7.0 million and $9.7 million, respectively.

In January 2014, the Compensation Committee awarded 233,735 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

As of December 31, 2013, total compensation cost related to performance units not yet recognized was approximately $10.8 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries.

Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy.

Wisconsin Electric and Wisconsin Gas are required to maintain capital structures that differ from GAAP as they reflect regulatory adjustments. The 2013 PSCW rate case order requires Wisconsin Electric to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas to maintain a capital structure which has a common equity range of between 45.0% and 50.0%. Each company is in compliance with its respective common equity range. Wisconsin Electric and Wisconsin Gas must obtain PSCW approval if they pay dividends above the test year levels that would cause either company to fall below the authorized levels of common equity.

Wisconsin Electric may not pay common dividends to Wisconsin Energy under Wisconsin Electric's Restated Articles of Incorporation if any dividends on Wisconsin Electric's outstanding preferred stock have not been paid. In addition, pursuant to the terms of Wisconsin Electric's 3.60% Serial Preferred Stock, Wisconsin Electric's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if Wisconsin Electric's common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

We have the option to defer interest payments on the Junior Notes, from time to time, for one or more periods of up to 10 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, repurchase or acquire, our common stock.

As of December 31, 2013, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method total approximately $3.6 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2013.

See Note K for discussion of certain financial covenants related to the bank back-up credit facilities of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Share Repurchase Program: We do not expect to issue new shares under our various employee benefit plans and our dividend reinvestment and share purchase plan; rather, we instruct independent plan agents to purchase the shares in the open market. In that regard, no new shares of common stock were issued in 2013, 2012 or 2011.

In May 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Through December 31, 2013, we repurchased approximately 7.7 million shares pursuant to this program at an average cost of $36.19 per share and a total cost of $277.8 million. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company for the year ending December 31:

	2013		2012		2011	
	Shares	Cost	Shares	Cost	Shares	Cost
	(In Millions)					
Under May 2011 share repurchase program	3.0	$ 126.0	1.5	$ 51.8	3.2	$ 100.0
To fulfill exercised stock options and restricted stock awards	2.4	97.4	2.8	101.4	3.0	93.9
Total	5.4	$ 223.4	4.3	$ 153.2	6.2	$ 193.9

On December 5, 2013, our Board of Directors authorized a new share repurchase program for management to purchase up to $300 million of the Company's common stock through open market purchases or privately negotiated transactions from January 1, 2014 through the end of 2017. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time.

I -- PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2013 and 2012:

	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
				(In Millions)
Wisconsin Energy				
$.01 par value Preferred Stock	15,000,000	—	—	$ —
Wisconsin Electric				
$100 par value, Six Per Cent. Preferred Stock	45,000	44,498	—	$ 4.4
$100 par value, Serial Preferred Stock	2,286,500			
3.60% Series		260,000	$ 101	26.0
$25 par value, Serial Preferred Stock	5,000,000	—	—	—
Total preferred stock of subsidiary				$ 30.4

J -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2013, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2014	$ 322.4
2015	399.5
2016	27.4
2017	29.5
2018	281.1
Thereafter	3,566.8
Total	$ 4,626.7

We amortize debt premiums, discounts and debt issuance costs over the lives of the debt and we include the costs in interest expense.

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2013 and 2012, the repurchased bonds were still outstanding, but were not reported in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

In connection with our outstanding Junior Notes, we executed the Replacement Capital Covenant dated May 11, 2007 (RCC) for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease or purchase and our subsidiaries may not purchase any Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, during the 180 days prior to the date of redemption, defeasance or purchase, we have received a specified amount of proceeds from the sale of qualifying securities.

Obligations Under Capital Leases: In 1997, Wisconsin Electric entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a gas-fired cogeneration facility, includes no minimum energy requirements. When the contract expires in 2022, Wisconsin Electric may, at its option and with proper notice, renew for another ten years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $33.7 million and $32.5 million in lease payments during 2013 and 2012, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $104.3 million as of December 31, 2013, and will decrease to zero over the remaining life of the contract.

The following is a summary of our capitalized leased facilities as of December 31:

Capital Lease Assets	2013	2012
	(Millions of Dollars)	
Leased Facilities		
Long-term power purchase commitment	$ 140.3	$ 140.3
Accumulated amortization	(92.5)	(86.8)
Total Leased Facilities	$ 47.8	$ 53.5

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2013 are as follows:

	(Millions of Dollars)
2014	$ 41.9
2015	43.5
2016	45.1
2017	13.9
2018	14.7
Thereafter	56.8
Total Minimum Lease Payments	215.9
Less: Estimated Executory Costs	(61.7)
Net Minimum Lease Payments	154.2
Less: Interest	(49.9)
Present Value of Net Minimum Lease Payments	104.3
Less: Due Currently	(19.8)
	$ 84.5

K -- SHORT-TERM DEBT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

	2013		2012	
Short-Term Debt	Balance	Interest Rate	Balance	Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$ 537.4	0.20%	$ 394.6	0.30%

The following information relates to commercial paper for the years ended December 31:

	2013	2012
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$ 594.5	$ 669.9
Average Short-Term Debt Outstanding	$ 359.1	$ 481.6
Weighted-Average Interest Rate	0.25%	0.28%

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require the companies to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%, 65% and 65%, respectively.

As of December 31, 2013, we had approximately $1.2 billion of available undrawn lines under our bank back-up credit facilities and $537.4 million of commercial paper outstanding that was supported by the available lines of credit. Our bank back-up credit facilities expire in December 2017.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with several of the covenants contained therein.

As of December 31, 2013, we were in compliance with all financial covenants.

L -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of December 31, 2013, we recognized $0.3 million in regulatory assets and $9.6 million in regulatory liabilities related to derivatives in comparison to $7.6 million in regulatory assets and $17.5 million in regulatory liabilities as of December 31, 2012.

We record our current derivative assets on the balance sheet in other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.4 million is recorded in other deferred charges and other assets, and we had no long-term portion of derivative liabilities. Our Consolidated Balance Sheets as of December 31, 2013 and 2012 include:

	December 31, 2013		December 31, 2012	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$ 5.6	$ 0.1	$ 3.0	$ 1.9
Fuel Oil	0.6	—	0.4	—
FTRs	3.5	—	4.7	—
Coal	2.1	0.2	11.1	—
Total	$ 11.8	$ 0.3	$ 19.2	$ 1.9

Our Consolidated Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the years ended December 31 were as follows:

	2013			2012		
	Volume	Gains (Losses)		Volume	Gains (Losses)	
		(Millions of Dollars)			(Millions of Dollars)	
Natural Gas	48.6 million Dth	$	(8.5)	77.2 million Dth	$	(36.3)
Fuel Oil	8.6 million gallons		0.5	7.0 million gallons		1.8
FTRs	25.3 million MWh		14.9	25.1 million MWh		6.1
Total		$	6.9		$	(28.4)

As of December 31, 2013 and 2012, we posted collateral of zero and $2.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

The fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. The table below shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on the balance sheet as of December 31, 2013 and 2012.

	2013		2012	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Gross Amount Recognized on the Balance Sheet	$ 11.8	$ 0.3	$ 19.2	$ 1.9
Gross Amount Not Offset on Balance Sheet (a)	—	—	(0.5)	(1.8)
Net Amount	$ 11.8	$ 0.3	$ 18.7	$ 0.1

(a) Gross Amount Not Offset on Balance Sheet includes cash collateral posted of zero and $1.3 million as of December 31, 2013 and 2012, respectively.

M -- FAIR VALUE MEASUREMENTS

Fair value measurements require enhanced disclosures about assets and liabilities that are measured and reported at fair value and establish a hierarchal disclosure framework which prioritizes and ranks the level of observable inputs used in measuring fair value.

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. Accordingly, we also utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities measured and reported at fair value are classified and disclosed in one of the following categories:

Level 1 -- Pricing inputs are unadjusted quoted prices 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. Instruments in this category consist of financial instruments such as exchange-traded derivatives, cash equivalents and restricted cash investments.

Level 2 -- Pricing inputs are other than quoted prices in active markets, which are either directly or indirectly observable as of the reporting date, and fair value is determined through the use of models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as Over-the-Counter (OTC) forwards and options.

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to fair value reporting and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, an instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the instrument.

The following tables summarize our financial assets and liabilities by level within the fair value hierarchy:

Recurring Fair Value Measures	As of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Derivatives	$ 5.7	$ 2.6	$ 3.5	11.8
Total	$ 5.7	$ 2.6	$ 3.5	$ 11.8
Liabilities:				
Derivatives	$ —	$ 0.3	$ —	$ 0.3
Total	$ —	$ 0.3	$ —	$ 0.3

Recurring Fair Value Measures	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 2.7	$ —	$ —	$ 2.7
Derivatives	2.2	12.3	4.7	19.2
Total	$ 4.9	$ 12.3	$ 4.7	$ 21.9
Liabilities:				
Derivatives	$ 1.9	$ —	$ —	$ 1.9
Total	$ 1.9	$ —	$ —	$ 1.9

We adopted ASU 2013-01, Disclosures about Offsetting Assets and Liabilities, on a retrospective basis. For additional information, see Note B -- Recent Accounting Pronouncements and Note L -- Derivative Instruments.

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the DOE during the first quarter of 2011, which was returned, net of costs incurred, to customers. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy:

	2013	2012
	(Millions of Dollars)	
Balance as of January 1	$ 4.7	$ 5.7
Realized and unrealized gains (losses)	—	—
Purchases	10.6	11.0
Issuances	—	—
Settlements	(11.8)	(12.0)
Transfers in and/or out of Level 3	—	—
Balance as of December 31	$ 3.5	$ 4.7
Change in unrealized gains (losses) relating to instruments still held as of December 31	$ —	$ —

Derivative instruments reflected in Level 3 of the hierarchy include MISO FTRs that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note L -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

The carrying amount and estimated fair value of certain of our recorded financial instruments as of December 31 are as follows:

	2013		2012	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$ 30.4	$ 26.0	$ 30.4	$ 26.0
Long-term debt including current portion	$ 4,626.7	$ 4,911.8	$ 4,772.9	$ 5,447.3

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases and unamortized discount on debt, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows.

N -- BENEFITS

Pensions and Other Post-retirement Benefits: We have defined benefit pension plans that cover substantially all of our employees. Generally, employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. Approximately half of our projected benefit obligation relates to benefits based upon years of service and final average salary.

We also have OPEB plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following table presents details about our pension and OPEB plans:

	Pension		OPEB	
	2013	2012	2013	2012
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$ 1,508.5	$ 1,330.6	$ 381.2	$ 389.7
Service cost	14.6	21.7	10.0	10.3
Interest cost	60.4	65.5	15.6	20.3
Participants' contributions	—	—	8.9	9.6
Plan amendments	(1.0)	—	—	0.5
Actuarial loss (gain)	(81.9)	166.5	(27.7)	(23.8)
Other accrued benefits	—	31.4	—	—
Gross benefits paid	(90.4)	(107.2)	(26.3)	(26.3)
Federal subsidy on benefits paid	N/A	N/A	1.0	0.9
Benefit Obligation at December 31	$ 1,410.2	$ 1,508.5	$ 362.7	$ 381.2
Change in Plan Assets				
Fair Value at January 1	$ 1,385.4	$ 1,262.5	$ 285.4	$ 255.4
Actual earnings on plan assets	147.3	127.4	45.5	29.0
Employer contributions	8.7	102.7	14.1	17.7
Participants' contributions	—	—	8.9	9.6
Gross benefits paid	(90.4)	(107.2)	(26.3)	(26.3)
Fair Value at December 31	$ 1,451.0	$ 1,385.4	$ 327.6	$ 285.4
Net asset (liability)	$ 40.8	$ (123.1)	$ (35.1)	$ (95.8)

As of December 31, 2013, our qualified pension plan was over-funded by $138.7 million and our non-qualified pension plan was under-funded by $97.9 million. As of December 31, 2012, our qualified and non-qualified pension plans were under-funded by $20.9 million and $102.2 million, respectively.

Amounts recognized in our Consolidated Balance Sheets as of December 31 related to the funded status of the benefit plans consisted of:

	Pension		OPEB	
	2013	2012	2013	2012
	(Millions of Dollars)			
Other long-term assets	$ 138.7	$ —	$ 40.2	$ 25.1
Other long-term liabilities	$ 97.9	$ 123.1	$ 75.3	$ 120.9

The accumulated benefit obligation for all defined pension plans was $1,409.5 million and $1,507.1 million as of December 31, 2013, and 2012, respectively.

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31 and are recorded as a regulatory asset on our balance sheet:

	Pension		OPEB	
	2013	2012	2013	2012
	(Millions of Dollars)			
Net actuarial loss	$ 528.8	$ 719.2	$ 9.8	$ 65.3
Prior service costs (credits)	8.8	12.2	(1.7)	(3.7)
Total - Regulatory Assets	$ 537.6	$ 731.4	$ 8.1	$ 61.6

We estimate that 2014 periodic pension and OPEB costs will include the amortization of previously unrecognized benefit costs (credits) referred to above of $38.7 million and $(0.9) million, respectively.

The components of net periodic pension and OPEB costs for the years ended December 31 are as follows:

	Pension			OPEB		
	2013	2012	2011	2013	2012	2011
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$ 14.6	$ 21.7	$ 15.9	$ 10.0	$ 10.3	$ 10.4
Interest cost	60.4	65.5	67.6	15.6	20.3	20.8
Expected return on plan assets	(95.8)	(89.6)	(82.1)	(21.3)	(19.0)	(16.9)
Amortization of:						
Transition obligation	—	—	—	—	0.3	0.3
Prior service cost (credit)	2.3	2.2	2.2	(2.0)	(1.9)	(1.9)
Actuarial loss	54.5	41.0	34.0	3.7	7.3	6.2
Settlement charge	2.5	—	—	—	—	—
Other	—	0.4	—	—	—	—
Net Periodic Benefit Cost	$ 38.5	$ 41.2	$ 37.6	$ 6.0	$ 17.3	$ 18.9

	Pension			OPEB		
	2013	2012	2011	2013	2012	2011
Weighted-Average assumptions used to determine benefit obligations as of Dec. 31						
Discount rate	5.00%	4.10%	5.05%	4.95%	4.15%	5.20%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	4.10%	5.05%	5.60%	4.15%	5.20%	5.70%
Expected return on plan assets	7.25%	7.25%	7.25%	7.50%	7.50%	7.50%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A

Assumed health care cost trend rates as of Dec. 31	2013	2012	2011
Health care cost trend rate assumed for next year (Pre 65 / Post 65)	7.5%/7.5%	7.5%/7.5%	8.0%/12%
Rate that the cost trend rate gradually adjusts to	5.0%	5.0%	5.0%
Year that the rate reaches the rate it is assumed to remain at (Pre 65 / Post 65)	2021/2021	2017/2017	2017/2017

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.50%, respectively, in 2013, 2012 and 2011. We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$ 26.4	$ (22.3)
Total of service and interest cost components	$ 3.2	$ (2.6)

We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds.

Plan Assets: Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

Our current pension plan target asset allocation is 45% equity investments and 55% fixed income investments. The current OPEB target asset allocation is 60% equity investments and 40% fixed income investments. Equity securities include investments in large-cap, mid-cap and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and U.S. Treasuries.

The following table summarizes the fair value of our pension plan assets by asset category within the fair value hierarchy (for further level information, see Note M):

	As of December 31, 2013			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 21.0	$ —	$ —	$ 21.0
Equities:				
U.S. Equity	519.5	—	—	519.5
International Equity	146.2	35.7	—	181.9
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	108.4	505.2	—	613.6
International Bonds	78.1	36.9	—	115.0
Total	$ 873.2	$ 577.8	$ —	$ 1,451.0

	As of December 31, 2012			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 13.7	$ —	$ —	$ 13.7
Equities:				
U.S. Equity	466.3	—	—	466.3
International Equity	134.7	30.4	—	165.1
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	67.7	546.6	—	614.3
International Bonds	80.7	45.3	—	126.0
Total	$ 763.1	$ 622.3	$ —	$ 1,385.4

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

The following table summarizes the fair value of our OPEB plan assets by asset category within the fair value hierarchy:

Asset Category - OPEB	As of December 31, 2013 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 2.6	$ —	$ —	$ 2.6
Equities:				
U.S. Equity	148.0	—	—	148.0
International Equity	46.9	2.8	—	49.7
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	8.4	96.3	—	104.7
International Bonds	16.8	5.8	—	22.6
Total	$ 222.7	$ 104.9	$ —	$ 327.6

Asset Category - OPEB	As of December 31, 2012 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 1.7	$ —	$ —	$ 1.7
Equities:				
U.S. Equity	125.9	—	—	125.9
International Equity	39.9	2.2	—	42.1
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	5.0	89.9	—	94.9
International Bonds	15.4	5.4	—	20.8
Total	$ 187.9	$ 97.5	$ —	$ 285.4

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

Cash Flows:

Historical employer contributions:

Year	Pension Qualified	Pension Non-Qualified	OPEB
	(Millions of Dollars)		
2011	$ 236.4	$ 6.5	$ 48.4
2012	$ 95.6	$ 7.1	$ 17.7
2013	$ —	$ 8.7	$ 14.1

Estimated benefit payments:

Year	Pension	Gross OPEB
	(Millions of Dollars)	
2014	$ 103.9	$ 24.2
2015	$ 98.6	$ 21.6
2016	$ 100.3	$ 22.0
2017	$ 100.9	$ 22.6
2018	$ 100.2	$ 23.4
2019-2023	$ 495.6	$ 119.7

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. Under these plans, we expensed matching contributions of $14.2 million, $13.8 million and $14.1 million during 2013, 2012 and 2011, respectively.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $4.2 million and $4.0 million as of December 31, 2013 and 2012, respectively.

O -- SEGMENT REPORTING

Our reportable segments as of December 31, 2013 include a utility energy segment and a non-utility energy segment. We have organized our reportable segments based upon the regulatory environment in which our utility subsidiaries operate and on how management makes decisions and measures performance. The segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our utility energy segment primarily includes our electric and natural gas utility operations. Our electric utility operation engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. Our non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Summarized financial information concerning our reportable segments for each of the three years ended December 31, 2013 is shown in the following table.

	Reportable Segments			Eliminations	
	Energy		Corporate &	& Reconciling	Total
Year Ended	Utility	Non-Utility	Other (a)	Items	Consolidated
			(Millions of Dollars)		
December 31, 2013					
Operating Revenues (b)	$ 4,462.0	$ 446.7	$ 1.3	$ (391.0)	$ 4,519.0
Depreciation and Amortization	$ 320.2	$ 67.1	$ 0.8	$ —	$ 388.1
Operating Income (Loss)	$ 719.4	$ 367.1	$ (6.4)	$ —	$ 1,080.1
Equity in Earnings of Unconsolidated Affiliates	$ 68.5	$ —	$ (0.1)	$ —	$ 68.4
Interest Expense, Net	$ 136.2	$ 65.7	$ 50.8	$ (0.6)	$ 252.1
Income Tax Expense (Benefit)	$ 243.6	$ 120.2	$ (25.9)	$ —	$ 337.9
Net Income (Loss)	$ 425.1	$ 181.6	$ 577.2	$ (606.5)	$ 577.4
Capital Expenditures	$ 657.9	$ 26.1	$ 3.4	$ —	$ 687.4
Total Assets (c)	$ 14,460.4	$ 2,846.5	$ 4,719.5	$ (7,257.0)	$ 14,769.4

Year Ended	Reportable Segments: Energy: Utility	Reportable Segments: Energy: Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
December 31, 2012					
Operating Revenues (b)	$ 4,190.8	$ 439.9	$ 1.2	$ (385.5)	$ 4,246.4
Depreciation and Amortization	$ 296.4	$ 67.1	$ 0.7	$ —	$ 364.2
Operating Income (Loss)	$ 647.7	$ 358.8	$ (6.2)	$ —	$ 1,000.3
Equity in Earnings of Unconsolidated Affiliates	$ 65.7	$ —	$ (0.2)	$ —	$ 65.5
Interest Expense, Net	$ 129.4	$ 66.7	$ 52.5	$ (0.4)	$ 248.2
Income Tax Expense (Benefit)	$ 214.9	$ 116.6	$ (25.2)	$ —	$ 306.3
Net Income (Loss)	$ 400.6	$ 175.9	$ 546.1	$ (576.3)	$ 546.3
Capital Expenditures	$ 697.3	$ 5.5	$ 4.2	$ —	$ 707.0
Total Assets (c)	$ 13,988.1	$ 2,903.5	$ 4,431.4	$ (7,038.0)	$ 14,285.0
December 31, 2011					
Operating Revenues (b)	$ 4,431.5	$ 435.1	$ 0.9	$ (381.1)	$ 4,486.4
Depreciation and Amortization	$ 257.0	$ 72.5	$ 0.7	$ —	$ 330.2
Operating Income (Loss)	$ 544.8	$ 348.9	$ (6.4)	$ —	$ 887.3
Equity in Earnings of Unconsolidated Affiliates	$ 62.5	$ —	$ (0.9)	$ —	$ 61.6
Interest Expense, Net	$ 110.0	$ 66.7	$ 59.5	$ (0.4)	$ 235.8
Income Tax Expense (Benefit)	$ 182.7	$ 112.8	$ (31.6)	$ —	$ 263.9
Income from Discontinued Operations, Net of Tax	$ —	$ —	$ 13.4	$ —	$ 13.4
Net Income (Loss)	$ 376.3	$ 169.8	$ 525.9	$ (545.8)	$ 526.2
Capital Expenditures	$ 792.2	$ 31.2	$ 7.4	$ —	$ 830.8
Total Assets (c)	$ 13,433.5	$ 2,949.0	$ 4,694.8	$ (7,215.2)	$ 13,862.1

(a) Corporate & Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark as well as interest on corporate debt.

(b) An elimination for intersegment revenues is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

(c) An elimination of $2,231.2 million, $2,286.7 million and $2,369.0 million is included in Total Assets as of December 31, 2013, 2012 and 2011, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

P -- RELATED PARTIES

We receive and/or provide certain services to other associated companies in which we have an equity investment.

American Transmission Company LLC: As of December 31, 2013, we have a 26.2% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which is reimbursed to us by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while projects are under construction, including the generating units constructed as part of our PTF strategy. ATC reimburses us for these costs when new generation is placed in service.

The following table summarizes material related party transactions with ATC during 2013, 2012 and 2011:

Equity Investee	2013	2012	2011
		(Millions of Dollars)	
Equity in Earnings	$ 68.5	$ 65.7	$ 62.5
Distributions Received	$ 54.5	$ 52.6	$ 49.7
Services Provided	$ 9.0	$ 8.2	$ 10.8
Services Received	$ 234.2	$ 222.7	$ 219.2

As of December 31, 2013 and 2012, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2013	2012
	(Millions of Dollars)	
Accounts Receivable		
Services provided	$ 0.6	$ 0.5
Accounts Payable		
Services received	$ 19.5	$ 18.6

Q -- COMMITMENTS AND CONTINGENCIES

Operating Leases: We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2018. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases including leases for coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2014	$ 3.9
2015	3.9
2016	3.7
2017	3.1
2018	3.2
Thereafter	22.7
Total	$ 40.5

Divested Assets: Pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5.

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal combustion product disposal sites. We perform ongoing assessments of manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal combustion product disposal/landfill sites used by Wisconsin Electric, as discussed below. We are working with the WDNR in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $19 million to $56 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of December 31, 2013 and 2012, we established reserves of $36.9 million and $38.2 million, respectively, related to future remediation costs.

Historically, the PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Coal Combustion Product Landfill Sites: Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required various levels of monitoring or remediation. Where Wisconsin Electric has become aware of these conditions, efforts have been made to define the nature and extent of any release, and work has been performed to address these conditions. During 2013, 2012 and 2011, Wisconsin Electric incurred $0.1 million, $0.3 million and $0.2 million respectively, in landfill remediation expenses. As of December 31, 2013, we have no reserves established related to coal combustion product landfill sites.

Valley Power Plant Title V Air Permit: The WDNR renewed VAPP's Title V operating permit in February 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested and were granted an administrative hearing before the WDNR on certain conditions of the permit; however, the case has been stayed. In addition, in March 2011, the Sierra Club petitioned the EPA for additional reductions and monitoring for particulate matter and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition. In May 2012, the Sierra Club filed a notice of intent to bring suit to force the EPA to issue a response to that petition. We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of either proceeding the permit is remanded to the WDNR, the plant will continue to operate under the previous operating permit.

In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas and anticipate that the conversion will be completed by the end of 2015 or early 2016. We currently expect the cost of this conversion to be between $65 million and $70 million, excluding AFUDC. We filed for a Certificate of Authority from the PSCW on April 26, 2013, and received preliminary approval on January 30, 2014. We expect to receive a final written order by the end of the first quarter. We received a construction air permit from the WDNR on November 11, 2013.

R -- SUPPLEMENTAL CASH FLOW INFORMATION

During the year ended December 31, 2013, we paid $250.4 million in interest, net of amounts capitalized, and received $39.6 million in net refunds from income taxes. During the year ended December 31, 2012, we paid $241.2 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes. During the year ended December 31, 2011, we paid $234.0 million in interest, net of amounts capitalized, and received $109.1 million in net refunds from income taxes.

As of December 31, 2013, 2012 and 2011, the amount of accounts payable related to capital expenditures was $4.7 million, $15.7 million and $16.7 million, respectively.

During the years ended December 31, 2013, 2012 and 2011, total amortization of deferred revenue was $56.5 million, $54.9 million and $54.4 million, respectively.

During the year ended December 31, 2013, we recorded an $82.6 million receivable related to the Treasury Grant. In conjunction with this transaction, we recognized $48.0 million as income, and deferred the balance.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated income statements, statements of common equity, and statements of cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 Wisconsin Energy Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

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, 2013, based on the criteria established in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 27, 2014

Deloitte.

Deloitte & Touche LLP
555 E. Wells Street, Suite 1400
Milwaukee, WI 53202-3824
USA

Tel: 414-271-3000
Fax: 414-347-6200
www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2013, based on the criteria established in *Internal Control - Integrated Framework* (1992) 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's 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, 2013, based on the criteria established in *Internal Control - Integrated Framework* (1992) 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 as of and for the year ended December 31, 2013 of the Company and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 27, 2014

Member of
Deloitte Touche Tohmatsu

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting was effective as of December 31, 2013.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of 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.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on the effectiveness of Wisconsin Energy Corporation's and its subsidiaries' internal control over financial reporting as of December 31, 2013. Deloitte & Touche LLP's report is included in this report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2013 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2013	2012	2011	2010	2009
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 577.4	$ 546.3	$ 512.8	$ 454.4	$ 375.7
Earnings per share - Continuing Operations					
Basic	$ 2.54	$ 2.37	$ 2.20	$ 1.94	$ 1.61
Diluted	$ 2.51	$ 2.35	$ 2.18	$ 1.92	$ 1.59
Dividends per share of common stock	$ 1.445	$ 1.20	$ 1.04	$ 0.80	$ 0.675
Operating revenues (Millions)					
Utility energy	$ 4,462.0	$ 4,190.8	$ 4,431.5	$ 4,165.3	$ 4,092.0
Non-utility energy	446.7	439.9	435.1	320.2	163.1
Eliminations and Other	(389.7)	(384.3)	(380.2)	(283.0)	(154.2)
Total operating revenues	$ 4,519.0	$ 4,246.4	$ 4,486.4	$ 4,202.5	$ 4,100.9
As of December 31 (Millions)					
Total assets	$ 14,769.4	$ 14,285.0	$ 13,862.1	$ 13,059.8	$ 12,697.9
Long-term debt (including current maturities) and capital lease obligations	$ 4,705.4	$ 4,865.9	$ 4,646.9	$ 4,405.4	$ 4,171.5
Common Stock Closing Price	$ 41.34	$ 36.85	$ 34.96	$ 29.43	$ 24.92

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2013	2012	2013	2012
Operating revenues	$ 1,275.2	$ 1,191.2	$ 1,012.3	$ 944.7
Operating income	$ 321.0	$ 295.7	$ 229.5	$ 222.6
Total net income	$ 176.6	$ 172.1	$ 119.0	$ 119.3
Earnings per share of common stock (b)				
Basic	$ 0.77	$ 0.75	$ 0.52	$ 0.52
Diluted	$ 0.76	$ 0.74	$ 0.52	$ 0.51

	September		December	
Three Months Ended	2013	2012	2013	2012
Operating revenues	$ 1,053.2	$ 1,039.3	$ 1,178.3	$ 1,071.2
Operating income	$ 258.0	$ 280.6	$ 271.6	$ 201.4
Total net income	$ 137.5	$ 156.1	$ 144.3	$ 98.8
Earnings per share of common stock (b)				
Basic	$ 0.61	$ 0.68	$ 0.64	$ 0.43
Diluted	$ 0.60	$ 0.67	$ 0.63	$ 0.43

(a) Quarterly results of operations are not directly comparable because of seasonal and other factors. See Management's Discussion and Analysis of Financial Condition and Results of Operations.

(b) Quarterly earnings per share may not total to the amounts reported for the year because the computation is based on the weighted average common shares outstanding during each quarter.

PERFORMANCE GRAPH

The performance graph on the next page shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2008, in each of:

- Wisconsin Energy common stock;
- a Custom Peer Group Index;
- a recomprised Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

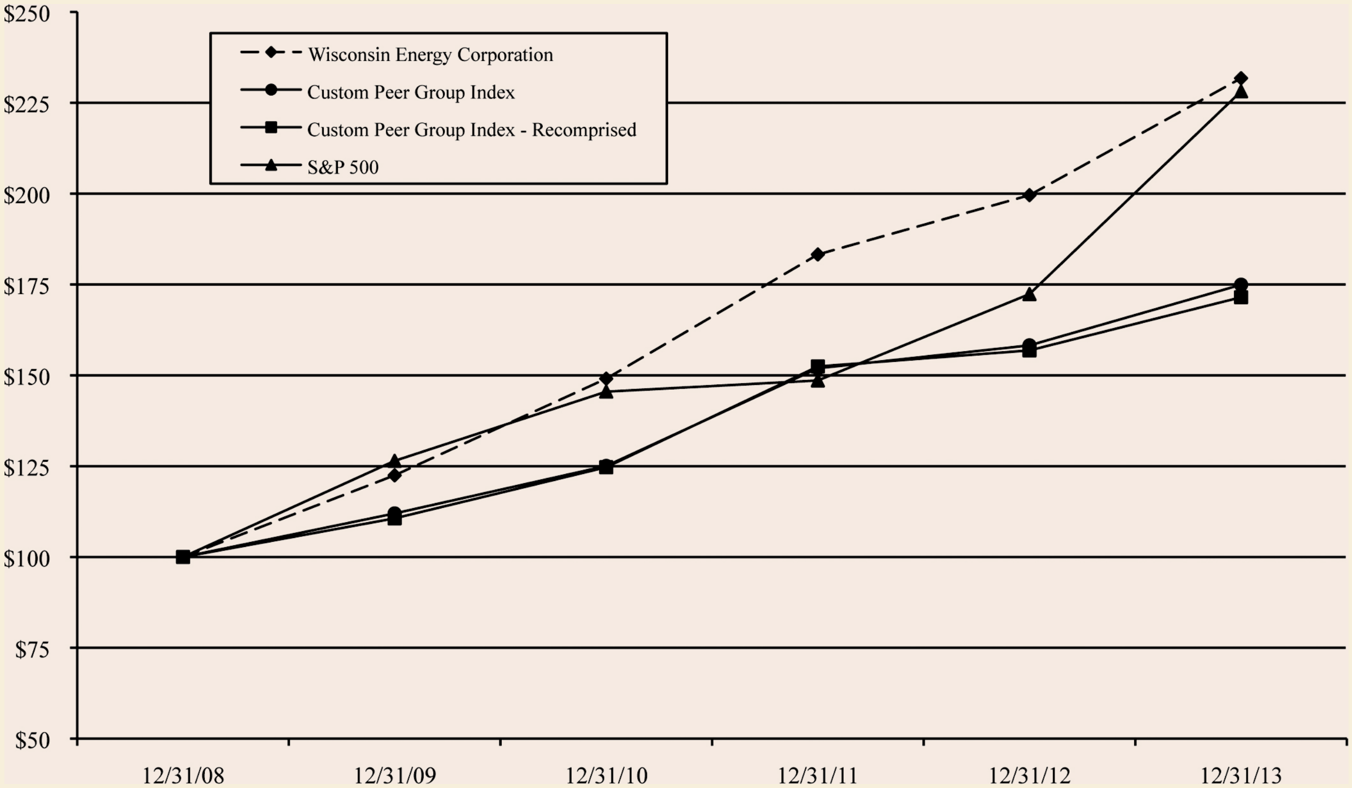
Custom Peer Group Index. We have used the Custom Peer Group Index for peer comparison purposes because we believed the Index provided an accurate representation of our peers. The Custom Peer Group Index is a market-capitalization-weighted index consisting of 27 companies, including Wisconsin Energy.

In addition to Wisconsin Energy, the companies in the Custom Peer Group Index are Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; FirstEnergy Corp.; Great Plains Energy, Inc.; Integrys Energy Group, Inc.; NiSource Inc.; Northeast Utilities; OGE Energy Corp.; Pepco Holdings, Inc.; PG&E Corporation; Pinnacle West Capital Corporation; Portland General; SCANA Corporation; Sempra Energy; The Southern Company; Westar Energy, Inc.; and Xcel Energy Inc.

In December 2013, MidAmerican Energy Holdings Company completed its purchase of NV Energy, Inc. NV Energy's common stock has since stopped trading on the New York Stock Exchange, and NV Energy filed to terminate the registration of its common stock. Therefore, in December 2013, the Compensation Committee determined that NV Energy, Inc. should be removed from the custom peer group.

Custom Peer Group Index – Recomprised. Beginning in 2013, we have recomprised our custom peer group to remove Sempra Energy as, over the next several years, it is expected that the percentage of Sempra's earnings from U.S. utility operations will drop as more growth is expected from its international operations, which is not consistent with our business model and long-term strategy. We have added CMS Energy Corporation to our custom peer group. We believe the Custom Peer Group Index, as recomprised, is made up of companies that are similar to us in terms of business model and long-term strategies.

Five-Year Cumulative Return Chart



Value of Investment at Year-End

	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13
Wisconsin Energy Corporation	$100	$122	$149	$183	$200	$232
Custom Peer Group Index	$100	$112	$125	$152	$158	$175
Custom Peer Group Index - Recomprised	$100	$111	$125	$152	$157	$171
S&P 500	$100	$126	$146	$149	$172	$228

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2013, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 39,755 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC."

DIVIDENDS AND COMMON STOCK PRICES

Common Stock Dividends of Wisconsin Energy: Cash dividends on our common stock, as declared by the Board of Directors, are normally paid on or about the first day of March, June, September and December of each year. We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition and other requirements. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note H -- Common Equity in the Notes to Consolidated Financial Statements.

In January 2013, our Board of Directors affirmed our dividend policy that targets a dividend payout ratio of 60% in the year 2014, and approved a new dividend policy that targets a payout ratio that trends to 65-70% in 2017. In accordance with that policy, on January 17, 2013, the Board increased our quarterly dividend to $0.34 per share effective with the first quarter of 2013 dividend payment. On July 18, 2013, the Board of Directors increased our quarterly dividend to $0.3825 per share effective with the third quarter of 2013 dividend payment.

On January 16, 2014, the Board of Directors increased the quarterly dividend to $0.39 per share effective with the first quarter of 2014 dividend payment, which would result in annual dividends of $1.56 per share. In addition, the Board affirmed our dividend policy that targets a dividend payout ratio of 65-70% in 2017.

Range of Wisconsin Energy Common Stock Prices and Dividends:

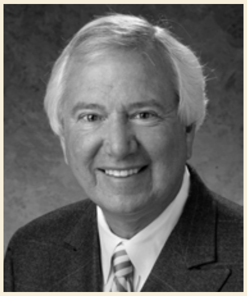
	2013			2012		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$ 42.98	$ 37.03	$ 0.3400	$ 35.35	$ 33.62	$ 0.30
Second	$ 45.00	$ 39.04	0.3400	$ 40.00	$ 34.54	0.30
Third	$ 44.01	$ 39.52	0.3825	$ 41.48	$ 37.46	0.30
Fourth	$ 43.00	$ 39.83	0.3825	$ 38.93	$ 36.01	0.30
Annual	$ 45.00	$ 37.03	$ 1.4450	$ 41.48	$ 33.62	$ 1.20

BOARD OF DIRECTORS

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the economy and the financial markets.



Curt S. Culver
Director since 2004.
Chairman and Chief Executive Officer of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting and governance matters.

Gale E. Klappa
Director since 2003.
Chairman and Chief Executive Officer of Wisconsin Energy Corporation.

Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a manufacturer of electrical and mechanical motion control products.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2013 of Wisconsin Energy's officers are listed below.

Gale E. Klappa[1] – Chairman of the Board and Chief Executive Officer.

Allen L. Leverett[1] – President.

J. Patrick Keyes[1] – Executive Vice President and Chief Financial Officer.

Susan H. Martin[1] – Executive Vice President, General Counsel and Corporate Secretary.

Robert M. Garvin[1] – Senior Vice President – External Affairs.

Darnell K. DeMasters – Vice President – Federal Policy.

Stephen P. Dickson[1] – Vice President and Controller.

Walter J. Kunicki – Vice President.

Scott J. Lauber – Vice President and Treasurer.

Richard J. White – Vice President.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

[1] Executive Officers of Wisconsin Energy Corporation as of December 31, 2013. Kevin Fletcher, Senior Vice President of Wisconsin Electric Power Company and Wisconsin Gas LLC, is also an executive officer of Wisconsin Energy Corporation.

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STOCKHOLDER INFORMATION

ACCOUNT INFORMATION

- Visit **www.computershare.com/investor.** Wisconsin Energy's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program from Computershare. eDelivery also features electronic delivery of your annual meeting materials.

- Write to:
  Wisconsin Energy Corporation
  c/o Computershare
  P.O. Box 30170
  College Station, TX 77842-3170

- If sending overnight correspondence, mail to:
  Wisconsin Energy Corporation
  c/o Computershare
  211 Quality Circle, Suite 210
  College Station, TX 77845

- Call Computershare at **800-558-9663**. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold Wisconsin Energy stock in brokerage accounts should contact their brokerage firm.

STOCK PURCHASE PLAN

Wisconsin Energy's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the Prospectus and enroll, go to **wisconsinenergy.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by Prospectus.

DIVIDENDS

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Contact Computershare to request an authorization form.

INTERNET ACCESS HELPS REDUCE COSTS

You may access **wisconsinenergy.com** for the latest information about Wisconsin Energy Corporation. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

ANNUAL CERTIFICATIONS

Wisconsin Energy has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2013. The certification of Wisconsin Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2014 Annual Meeting of Stockholders. Last year, we filed this certification on May 24, 2013.

CORPORATE SOCIAL RESPONSIBILITY

Wisconsin Energy is committed to corporate social responsibility and sustainable business practices — aligning our policies and practices with the needs of key stakeholders, and managing risk while accounting for the company's economic, environmental and social impacts. For additional information, visit **www.wisconsinenergy.com/csr.**

Wisconsin Energy Corporation

Wisconsin Energy Corporation

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MILWAUKEE, WI 53201

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wisconsinenergy.com

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