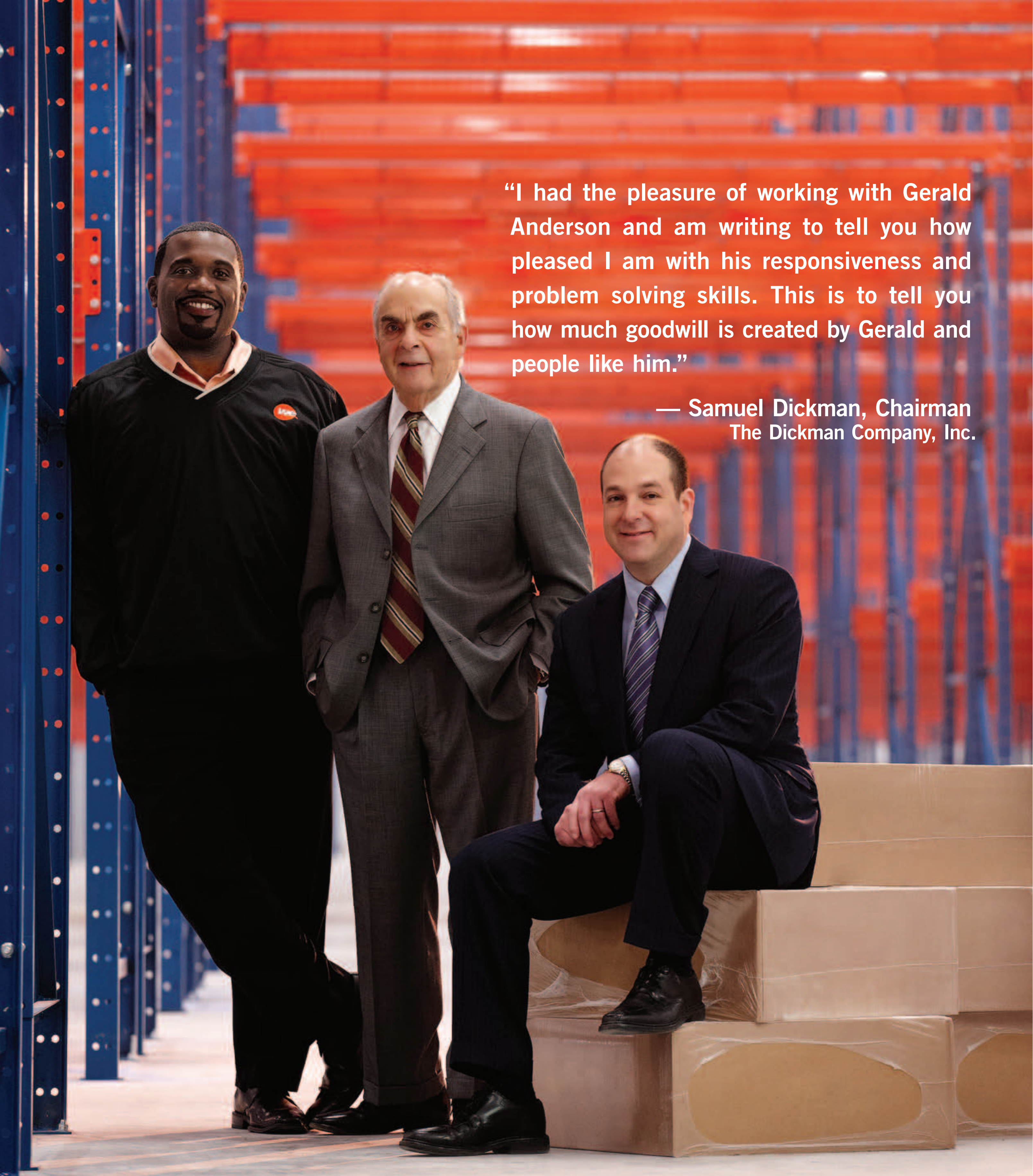
Wisconsin Energy Corporation

Planners Builders Value Creators

People you can trust. Energy you can depend on.

2011 Annual Report

WISCONSIN ENERGY CORPORATION 2011 Annual Report

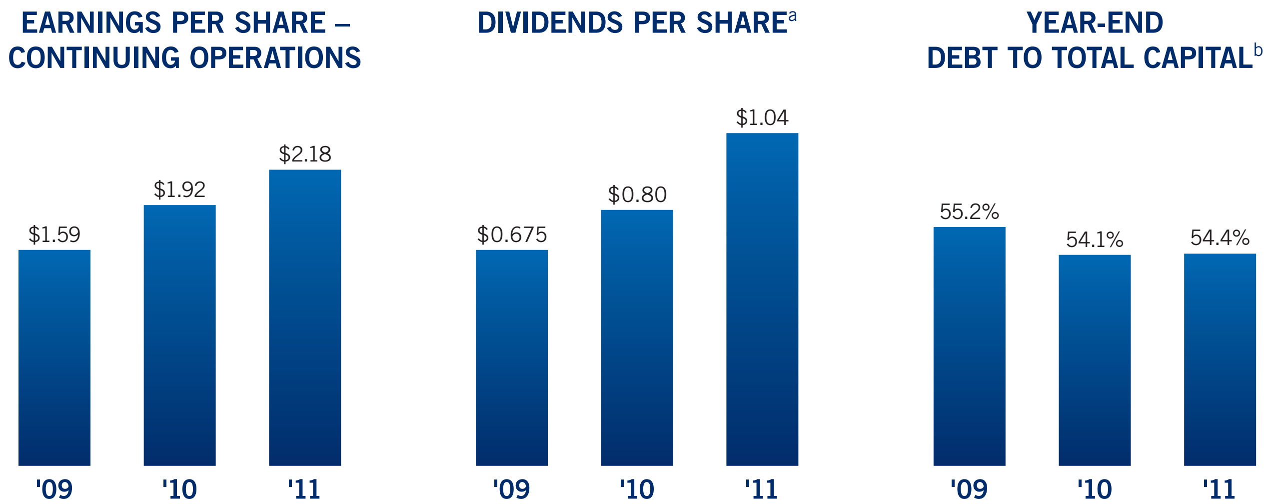


"I had the pleasure of working with Gerald Anderson and am writing to tell you how pleased I am with his responsiveness and problem solving skills. This is to tell you how much goodwill is created by Gerald and people like him."

— Samuel Dickman, Chairman
The Dickman Company, Inc.

The real estate company owned by Sam Dickman and his son was building a 122,000-square-foot warehouse in Oak Creek, Wis., when a problem arose with moving the underground utility lines — an issue that greatly affected access to the site. Facing severe time constraints, the Dickmans worked closely with Gerald Anderson, a customer service supervisor for We Energies. Gerald quickly assessed the problem, solved it and helped keep the project on schedule.

FINANCIAL HIGHLIGHTS



a. The quarterly dividend was increased from 26 cents per share to 30 cents per share in the first quarter of 2012.

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-18.

BEST IN THE MIDWEST — AGAIN

For the seventh time in 10 years, We Energies was named the most reliable utility in the Midwest. "ReliabilityOne award winners represent the very best our industry has to offer in terms of service quality," said the ReliabilityOne™ program director. "We Energies has once again demonstrated its unwavering commitment to customers by achieving the highest levels of reliability."

GALE E. KLAPPA

Chairman, President, and Chief Executive Officer

TO OUR STOCKHOLDERS,

I was at a busy airport the other day waiting with hundreds of other people to board an international flight. As I sat in the gate area, I was struck by the amazing number of people who were searching for electrical outlets to charge their laptops, tablets, and smartphones. At that moment, it occurred to me that the era of the portable, hand-held office — the era of instant information — would not have been possible without the genius of Edison. Nor would our digital age have been possible without the planners, builders, and value creators who developed the electric generating plants and distribution networks that literally power our lives today.

With that thought as a backdrop, I'd like to share with you what the planners, builders, and value creators at Wisconsin Energy achieved during 2011.

AN EXCEPTIONAL YEAR

I'm delighted to report that by virtually every meaningful measure, 2011 was an exceptional year for our company. We reported record net income and the highest earnings per share in the company's history. Our board of directors declared a two-for-one stock split that became effective during the first quarter of the year. And, in the first quarter of 2011, we raised the quarterly dividend by 30 percent as we continue to make significant progress toward a dividend payout that is more competitive with our peers in the regulated utility industry. More on our dividend policy later in this letter.

We also achieved major milestones in customer satisfaction, employee safety, and network reliability. And our total shareholder return continued to outperform the return you would've earned by investing in the Dow Jones Industrials, the S&P 500, NASDAQ, or any of the major utility indexes. In fact, as you can see in the performance table below, our total shareholder return for the past five years was head and shoulders above any of these investment alternatives.

TOTAL SHAREHOLDER RETURN* Five-Year Performance (2007–2011)	
WISCONSIN ENERGY	**69.7%**
Dow Jones Industrial Average	12.4%
S&P 500 Index	–1.2%
NASDAQ Composite Index	13.2%
Philadelphia Utility Index	20.1%
S&P Electric Index	18.2%

*Stock price appreciation plus reinvested dividends.

Of course, our engine of growth over much of the past decade has been our Power the Future plan. You may recall that Power the Future was born at a time of real need. As we entered the early 2000s faced with the prospect of summer brownouts and blackouts, it was clear that significant new investment was needed to upgrade the energy infrastructure in Wisconsin and Michigan's Upper Peninsula. The region's ability to attract jobs and support economic growth hung in the balance.

We've invested $7.8 billion in necessary infrastructure projects since 2003.

There were many challenges and obstacles along the way. But with focus, discipline, and determination, we moved from proposal to reality. Today, our Power the Future plan has come to fruition. Overall, we've invested $7.8 billion in necessary infrastructure projects since 2003. Much of that investment has been devoted to building four state-of-the-art generating units — two fueled by natural gas and two fueled by coal. These units are among the most efficient of their kind and will serve our customers well for many years to come.

Income from the company's Power the Future assets — particularly the two coal-fired generating units at our Oak Creek site — helped the company record earnings from continuing operations of $513 million or $2.18 a share in 2011.

Sales of electricity to our large commercial and industrial customers rose by 0.3 percent during the year. This modest growth occurred after a nearly double-digit rebound in energy usage by our large customers in 2010. We're continuing to see strength in several important sectors of the regional economy — most notably in specialty steel production, metal fabrication, industrial machinery, and printing and publishing.

While our Power the Future construction is complete, there is much more work to do — upgrading our environmental controls, renewing and strengthening our distribution networks, and completing the renewable energy projects that are necessary to meet the standard set by the state of Wisconsin for the year 2015. In fact, our five-year capital spending plan is projected to total $3.5 billion.

NEW AIR QUALITY CONTROLS

As I write this letter, we're nearing completion of the second largest construction project in company history. The air quality control upgrade for the four older coal-fired units at our Oak Creek site is about 95 percent complete. At a cost of approximately $900 million, the scrubbers and selective catalytic reduction facilities being built will dramatically reduce the emissions from these units. The units were built in the 1960s, but they remain among the most efficient base load plants in the Midwest. So the most economical solution for our customers was to undertake this major project — a project that will clearly extend the productive life of these units. We expect the new air quality controls — pictured on the facing page — to be fully operational this year.

We're continuing to add renewable energy to our portfolio as well, and we reached another milestone before the close of 2011. The Glacier Hills Wind Park — the largest wind farm in Wisconsin — was placed into commercial service on December 20. With 90 turbines and a capacity of 162 megawatts, Glacier Hills is located on more than 17,000 acres of rolling farmland about 45 miles northeast of Madison. Making extensive use of Wisconsin companies and labor, the project was completed on time and under the $363 million budget set by the state public service commission.

To add diversity to our renewable energy portfolio, we sought and received permission during 2011 to build a 50-megawatt biomass plant in Rothschild, Wisconsin. This plant will burn wood waste from the northern Wisconsin forests. It will produce electricity for the grid and steam for the paper mill that is owned and operated in Rothschild by the Domtar Corporation. Construction began last June, and we're projecting a completion date before the end of 2013 at a cost of approximately $250 million.

Together, these projects will position us well to meet the renewable energy standard for 2015.

PRESQUE ISLE POWER PLANT

Elsewhere on our system, proposed changes in federal environmental rules are compelling us to consider various options for the coal-fired units at our Presque Isle Power Plant in Marquette, Michigan.

Today we're exploring a potential joint venture opportunity with Wolverine Power Cooperative, a generation and transmission cooperative based in Cadillac, Michigan. We're evaluating a proposal that calls for Wolverine to fund the construction of new air quality controls at Presque Isle in return for a partial ownership interest in the plant. At this point in our review, it appears that the joint venture approach would benefit customers, but significant work — including a full engineering analysis — must be completed before a final decision is made.

Regardless of the decision about the future of Presque Isle, we believe that the transmission network must be strengthened in the Upper Peninsula to maintain reliability and support future economic growth. So, we're working with American Transmission Company to plan for new transmission lines in the U.P.

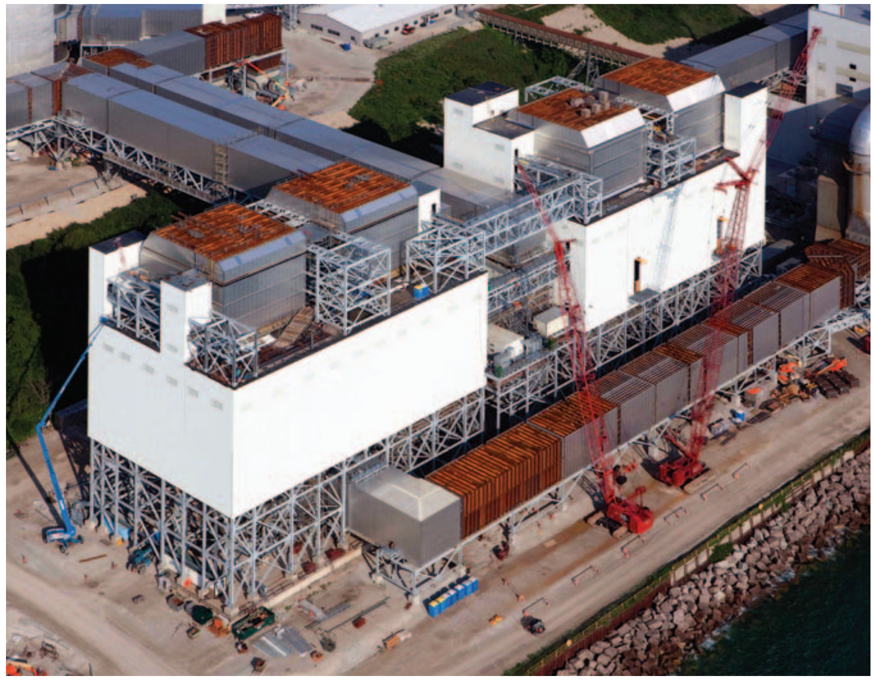
Our company was again named the most reliable electric utility in the Midwest.

RELIABILITY, SATISFACTION, SAFETY

Of course, in our business, there is no substitute for reliability. It's the cornerstone of customer satisfaction. So, I'm proud to report to you that our company was again named the most reliable electric utility in the Midwest — the seventh time in the past 10 years that we've been honored with this prestigious award.

Along with being the best in the Midwest for keeping the lights on, we continue to pursue our long-term goal of being the industry leader in customer satisfaction.

Customer satisfaction is not just a slogan at our company. It's a way of life.



We know that to achieve our goal, we must act with a true sense of urgency, demonstrate that we care during every customer contact, resolve customer problems the first time — every time, take personal responsibility for results, and communicate with our customers along the way. With this fundamental approach to doing business, our employees delivered new highs in customer satisfaction in 2011.

One other notable accomplishment during the year was our employee safety record. Not only was 2011 our safest year of operation ever, but we also experienced 66 percent fewer lost-time accidents in 2011 than we did in 2003.

Safety. Reliability. Customer satisfaction. Financial results. The record-breaking performance of 2011 speaks for itself.

MOVING FORWARD

But as I mentioned earlier in this letter, we have much more to accomplish. We approach the challenges of the next five years with a solid foundation and positive cash flows. We have strong, investment-grade credit ratings. Over the past year, we have returned additional value to shareholders by repurchasing $100 million of our common stock at an average price of $30.79 a share.

Going forward, we will benefit from an Internal Revenue Service ruling that we received in December affirming our belief that accelerated depreciation can be applied to the investment in our new Oak Creek units. The $285 million of cash from this accelerated depreciation will help fund the higher level of infrastructure investment we're projecting in our five-year spending plan.

Strong cash flows will also help support our revised dividend policy — a policy that calls for us to pay out 60 percent of our earnings in dividends in 2014 — one year earlier than our previous goal. As you may have read, our board took a positive step toward our new goal in January 2012 by approving a dividend increase of 15 percent payable with the first-quarter dividend. This brings our annual dividend rate to $1.20 a share.

Our revised dividend policy calls for us to pay out 60 percent of our earnings in dividends in 2014.

In closing, I'm reminded that former President Ronald Reagan was fond of saying that he took inspiration from the past, but he lived for the future.

At Wisconsin Energy, we live and plan for a future of resilience and growth. With a healthy blend of pragmatism and optimism, I believe that the best days of our company and the best days of our region are ahead.

On behalf of the planners, builders, and value creators at Wisconsin Energy, thank you for your confidence and support.

Sincerely,

Gale Klappa

Gale E. Klappa
Chairman, President, and Chief Executive Officer
March 7, 2012

GLACIER HILLS WIND PARK

A blade is lifted carefully into place for one of the 90 wind turbines at Glacier Hills Wind Park. Completed and placed into service in December 2011, Glacier Hills is the largest wind farm in Wisconsin — capable of generating enough electric energy to power 45,000 homes.

GAS PIPELINE REPLACEMENT

A 160-foot section of 24-inch diameter pipe is guided into a trench during a $4.4 million gas pipeline replacement project along a busy thoroughfare in Milwaukee, Wis. Some 7,500 feet of pipe was laid at night to minimize disruption to traffic and businesses. The project is just one part of our wide-ranging plan to upgrade and renew aging infrastructure across the region.

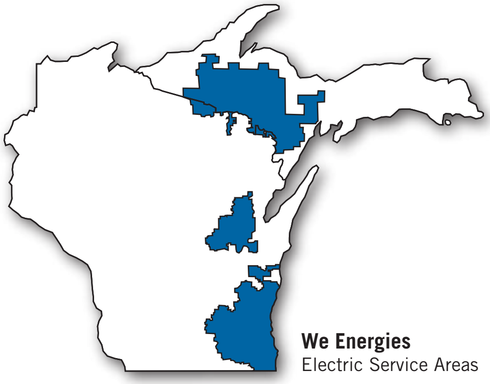
Construction began last June on a 50-megawatt biomass plant on the site of a paper mill owned by Domtar Corporation in Rothschild, Wis. In this photo, the boiler building (top) and the biomass storage building (lower) begin to take shape along the Wisconsin River. Scheduled for completion by the end of 2013, the plant will burn wood waste from sustainably harvested forests.

WISCONSIN ENERGY CORPORATION (NYSE: WEC) is one of the nation's premier energy companies with more than $13 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 more than 1 million natural gas customers in Wisconsin. The company's other major subsidiary, We Power, designs, builds and owns electric generating plants.

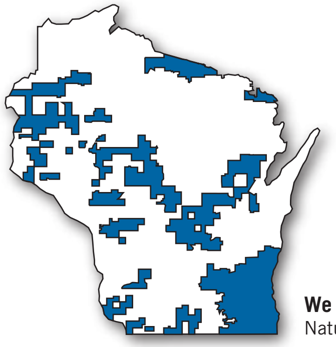
Headquartered in Milwaukee, Wisconsin Energy is a component of the S&P 500 with approximately 4,600 employees and more than 42,500 stockholders of record.

ELECTRIC CUSTOMERS AS OF DEC. 31, 2011: 1,122,500



We Energies
Electric Service Areas

NATURAL GAS CUSTOMERS AS OF DEC. 31, 2011: 1,068,200



We Energies
Natural Gas Service Areas

2011 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	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PWGS	Port Washington 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
ERS	Elm Road Services, LLC
WECC	Wisconsin Energy Capital Corporation
Wispark	Wispark 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
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
CAVR	Clean Air Visibility Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
FIP	Federal Implementation Plan
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
NODA	Notice of Data Availability
NOV	Notice of Violation
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
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
CPCN	Certificate of Public Convenience and Necessity
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act

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:

Edison Sault	Edison Sault Electric Company
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
GDP	Gross Domestic Product
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007
LLC	Limited Liability Company
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Moody's	Moody's Investor Service
NYMEX	New York Mercantile Exchange
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
PUHCA 2005	Public Utility Holding Company Act of 2005
RCC	Replacement Capital Covenant dated May 11, 2007
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
Settlement Agreement	Settlement Agreement and Release between ERS and Bechtel effective as of December 16, 2009
S&P	Standard & Poor's Ratings Services
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
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
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
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 (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, regulatory matters, on-going legal proceedings, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other 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 new 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; collective bargaining agreements with union employees or work stoppages; or inflation rates.

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

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with our *Power the Future* (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.

- Increased competition in our electric and gas markets and continued industry consolidation.

- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; 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 cybersecurity threats; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application 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 FERC matters and IRS audits and other tax matters.

- Failure of the court to approve the settlement agreement reached in the lawsuit against the Wisconsin Energy Corporation Retirement Account Plan (Plan).

- 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.

- 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.

- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and any regulations promulgated thereunder.

- 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, including any changes in regulatory accounting policies and practices and any requirement for U.S. registrants to follow International Financial Reporting Standards (IFRS) instead of Generally Accepted Accounting Principles (GAAP).

- Unanticipated technological developments 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.

- 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 business or investment considerations 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 operating 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 1,122,500 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,068,200 gas customers in Wisconsin and approximately 465 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 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 P -- Segment Reporting in the Notes to Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company with subsidiaries primarily in a utility energy segment and a non-utility energy segment. 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.

Our utility energy segment primarily consists of Wisconsin Electric and Wisconsin Gas, both doing business under the trade name of "We Energies." We generate and distribute electricity in Wisconsin and the Upper Peninsula of Michigan and we distribute natural gas in Wisconsin. Our non-utility energy segment primarily consists of We Power. We Power is principally engaged in the engineering, construction and development of electric power generating facilities for long-term lease to Wisconsin Electric under our PTF strategy.

CORPORATE STRATEGY

Business Opportunities

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 the electric and gas customers of We Energies. During 2011, our regulated utility earned $544.8 million of operating income. Over the next three years, we expect to invest approximately $2.0 billion in this business to construct renewable generation and environmental projects at our electric generation assets, to update the electric and gas distribution infrastructure, and for other utility projects.

We have a $349.7 million investment in ATC, which represents a 26.2% ownership interest. Our 2011 pre-tax earnings from ATC totaled $62.5 million and we received $49.7 million in dividends from ATC. Over the next three years, we expect to invest approximately $29.4 million in ATC as it continues to upgrade the transmission infrastructure within Wisconsin.

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 lease. During 2012, we expect this segment's operating income to be between $345 million and $350 million. Over the next three years, we expect to invest approximately $75 million in this segment. The PTF strategy was developed with the primary goal of constructing the four power plants discussed above. With the completion of the final PTF unit, OC 2, in January 2011, we believe that our future capital expenditures in this segment will consist primarily of smaller capital projects within the existing PTF units.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2011, 2010 and 2009:

Wisconsin Energy Corporation	2011	2010	2009
	(Millions of Dollars)		
Utility Energy	$ 544.8	$ 564.0	$ 550.9
Non-Utility Energy	348.9	252.4	120.1
Corporate and Other	(6.4)	(6.0)	(10.7)
Total Operating Income	887.3	810.4	660.3
Equity in Earnings of Transmission Affiliate	62.5	60.1	59.1
Other Income and Deductions, net	62.7	40.2	28.5
Interest Expense, net	235.8	206.4	156.7
Income from Continuing Operations Before Income Taxes	776.7	704.3	591.2
Income Tax Expense	263.9	249.9	215.5
Income from Continuing Operations	512.8	454.4	375.7
Income from Discontinued Operations, Net of Tax	13.4	2.1	6.7
Net Income	$ 526.2	$ 456.5	$ 382.4
Diluted Earnings Per Share			
Continuing Operations	$ 2.18	$ 1.92	$ 1.59
Discontinued Operations	0.06	0.01	0.03
Total Diluted Earnings Per Share	$ 2.24	$ 1.93	$ 1.62

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 2011, 2010 and 2009:

Utility Energy Segment	2011	2010	2009
	(Millions of Dollars)		
Operating Revenues			
Electric	$ 3,211.3	$ 2,936.3	$ 2,685.0
Gas	1,181.2	1,190.2	1,367.9
Other	39.0	38.8	39.1
Total Operating Revenues	4,431.5	4,165.3	4,092.0
Fuel and Purchased Power	1,174.5	1,104.7	1,064.5
Cost of Gas Sold	728.7	751.5	912.0
Gross Margin	2,528.3	2,309.1	2,115.5
Other Operating Expenses			
Other Operation and Maintenance	1,613.4	1,587.0	1,372.3
Depreciation and Amortization	257.0	251.4	313.1
Property and Revenue Taxes	113.1	105.1	109.9
Total Operating Expenses	3,886.7	3,799.7	3,771.8
Amortization of Gain	—	198.4	230.7
Operating Income	$ 544.8	$ 564.0	$ 550.9

2011 vs. 2010: Our utility energy segment contributed $544.8 million of operating income during 2011 compared with $564.0 million of operating income during 2010. The decrease in operating income was primarily caused by increased other operation and maintenance expense and unfavorable weather during 2011 as compared to the prior year, partially offset by wholesale electric pricing increases and electric sales growth.

2010 vs. 2009: Our utility energy segment contributed $564.0 million of operating income during 2010 compared with $550.9 million of operating income during 2009. The increase in operating income was primarily caused by favorable weather during 2010, partially offset by unfavorable recoveries of revenues associated with fuel and purchased power in 2010.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2011 with similar information for 2010 and 2009, including a summary of electric operating revenues and electric sales by customer class:

	Electric Revenues and Gross Margin			MWh Sales		
Electric Utility Operations	2011	2010	2009	2011	2010	2009
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	$ 1,159.2	$ 1,114.3	$ 977.6	8,278.5	8,426.3	7,949.3
Small Commercial/Industrial	1,006.9	922.2	860.3	8,795.8	8,823.3	8,571.6
Large Commercial/Industrial	763.7	677.1	599.4	9,992.2	9,961.5	9,140.3
Other - Retail	22.9	21.9	21.2	153.6	155.3	156.5
Total Retail	2,952.7	2,735.5	2,458.5	27,220.1	27,366.4	25,817.7
Wholesale - Other	154.0	134.6	116.7	2,024.8	2,004.6	1,529.4
Resale - Utilities	69.5	40.4	47.5	2,065.7	1,103.8	1,548.9
Other Operating Revenues	35.1	25.8	62.3	—	—	—
Total	3,211.3	2,936.3	2,685.0	31,310.6	30,474.8	28,896.0
Fuel and Purchased Power						
Fuel	644.4	570.5	518.3			
Purchased Power	514.8	521.0	533.8			
Total Fuel and Purchased Power	1,159.2	1,091.5	1,052.1			
Total Electric Gross Margin	$ 2,052.1	$ 1,844.8	$ 1,632.9			
Weather - Degree Days (a)						
Heating (6,615 Normal)				6,633	6,183	6,825
Cooling (709 Normal)				793	944	475

(a) 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

2011 vs. 2010: Our electric utility operating revenues increased by $275.0 million, or 9.4%, when compared to 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately $198.4 million, reflecting the reduction of Point Beach bill credits to retail customers. For information on the bill credits, see Amortization of Gain below.
- Net pricing increases totaling $48.8 million, which includes rates related to our 2010 fuel recovery request that became effective March 25, 2010, and our request to review 2011 fuel costs that became effective April 29, 2011. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Unfavorable weather as compared to the prior year that decreased electric revenues by an estimated $40.5 million.
- A $20.4 million increase in revenue from energy sold into the MISO Energy Markets, which was driven by increased MWh generation from our Oak Creek expansion units.

- Net economic growth that increased electric revenues by an estimated $16.2 million as compared to 2010.
- Higher MWh sales to our wholesale customers, which increased revenue by an estimated $10.4 million as compared to 2010.

As measured by cooling degree days, 2011 was 11.8% warmer than normal, but 16.0% cooler than 2010. The 1.8% decrease in residential sales volumes in 2011 is primarily attributable to weather. The estimated 1.8% impact of cooler summer weather on our small commercial/industrial sales volumes was almost entirely offset by an estimated 1.5% increase in sales due to modest economic growth. Increased sales to our largest customers, two iron ore mines, accounted for the increase in sales to our large commercial/industrial customers. If these sales are excluded, sales to our large commercial/industrial customers decreased by approximately 1.2% for 2011 as compared to 2010 primarily because of previously announced plant closings.

2010 vs. 2009: Our electric utility operating revenues increased by $251.3 million, or 9.4%, when compared to 2009. The most significant factors that caused a change in revenues were:

- Net pricing increases totaling $121.0 million related to Wisconsin and Michigan rate orders that became effective in 2010. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Favorable weather that increased electric revenues by an estimated $103.4 million as compared to 2009.
- Net economic growth that increased electric revenues by an estimated $43.0 million as compared to 2009.
- 2010 pricing increases totaling approximately $32.3 million, reflecting the reduction of Point Beach bill credits to retail customers.

As measured by cooling degree days, 2010 was 98.7% warmer than 2009 and 35.2% warmer than normal. Collectively, retail sales to our residential and small commercial/industrial customers, who are more weather sensitive, increased by 4.4%. Sales to our large commercial/industrial customers increased by 9.0% during 2010 as compared to 2009, primarily because of an improving economy. Electric sales to our largest customers, two iron ore mines, which represented approximately 6.9% of our annual sales in 2010, increased significantly for the year. If these sales are excluded, sales to our large commercial/industrial customers increased by 3.2% for 2010 as compared to 2009. The $36.5 million decline in Other Operating Revenues primarily relates to regulatory amortizations during 2010 as compared to 2009.

Electric Fuel and Purchased Power Expenses

2011 vs. 2010: Our electric fuel and purchased power costs increased by $67.7 million, or approximately 6.2%, when compared to 2010. This increase was primarily caused by a 2.7% increase in total MWh sales as well as increased coal and related transportation costs, partially offset by lower natural gas prices.

2010 vs. 2009: Our electric fuel and purchased power costs increased by $39.4 million, or approximately 3.7%, when compared to 2009. This increase was primarily caused by a 5.5% increase in total MWh sales, partially offset by a 1.6% decrease in the average cost/MWh between periods. The average cost/MWh was comparable between periods because of a 7.7% increase in generation from our lower cost coal units and a 16.5% decrease in the cost of natural gas used at the Port Washington Generating Station (PWGS), which was sufficient to offset the impact of a 5.7% increase in coal and related transportation costs and the increase in gas generation and purchased power utilized as a result of the increased sales.

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 2011, 2010 and 2009. Operating revenues and cost of gas sold has declined over the last three years due to the decline in the commodity cost of natural gas during this three year period.

Gas Utility Operations	2011	2010	2009
	(Millions of Dollars)		
Operating Revenues	$ 1,181.2	$ 1,190.2	$ 1,367.9
Cost of Gas Sold	728.7	751.5	912.0
Gross Margin	$ 452.5	$ 438.7	$ 455.9

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 (GCRM). The following table compares our gas utility gross margin and therm deliveries by customer class during 2011, 2010 and 2009:

Gas Utility Operations	Gross Margin 2011	Gross Margin 2010	Gross Margin 2009	Therm Deliveries 2011	Therm Deliveries 2010	Therm Deliveries 2009
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	$ 290.2	$ 282.2	$ 291.5	776.8	741.2	803.4
Commercial/Industrial	101.5	95.8	104.6	461.7	429.6	479.4
Interruptible	1.8	2.2	2.0	16.0	19.4	19.1
Total Retail	393.5	380.2	398.1	1,254.5	1,190.2	1,301.9
Transported Gas	52.6	51.3	49.6	899.6	914.9	882.0
Other Operating	6.4	7.2	8.2	—	—	—
Total	$ 452.5	$ 438.7	$ 455.9	2,154.1	2,105.1	2,183.9
Weather - Degree Days (a)						
Heating (6,615 Normal)				6,633	6,183	6,825

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

2011 vs. 2010: Our gas margin increased by $13.8 million, or approximately 3.1%, when compared to 2010 primarily because of an increase in sales volumes as a result of colder winter weather in 2011 as compared to 2010. As measured by heating degree days, 2011 was 7.3% colder than 2010 and 0.3% colder than normal.

Winter weather is the most significant variable for our gas margin.

2010 vs. 2009: Our gas margin decreased by $17.2 million, or approximately 3.8%, when compared to 2009 primarily because of a decline in sales volumes as a result of warmer winter weather in 2010 as compared to 2009. As measured by heating degree days, 2010 was 9.4% warmer than 2009 and 6.5% warmer than normal.

Other Operation and Maintenance Expense

2011 vs. 2010: Our other operation and maintenance expense increased by $26.4 million, or approximately 1.7%, when compared to 2010. Higher maintenance costs at one of our natural gas peaking plants, increased spending on forestry work for our electric distribution system and increased costs associated with the amortization of deferred PTF costs related to wholesale and Michigan customers were the primary drivers of the increase.

Our utility operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages and amortization of regulatory assets. We expect our 2012 other operation and maintenance expense to decrease by $148 million because of the one year elimination of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

2010 vs. 2009: Our other operation and maintenance expense increased by $214.7 million, or approximately 15.6%, when compared to 2009. The 2010 Public Service Commission of Wisconsin (PSCW) rate case order allowed for pricing increases related to regulatory items including PTF lease costs, bad debt expense and amortization of other deferred costs. We estimate that these items were approximately $87.3 million higher in 2010 as compared to 2009. In addition, operation and maintenance expenses at our power plants increased approximately $63.9 million primarily because of the operation of OC 1, which was placed in service in February 2010, and higher maintenance costs at our other power plants. We also had increased operation and maintenance expenses of approximately $20.8 million related to increased reliability maintenance in our distribution system in 2010 and responding to damage caused by a larger number of summer storms compared to 2009. In addition, our benefits expense increased by approximately $28.8 million in 2010 as compared to 2009 primarily because of increased pension costs.

Depreciation and Amortization Expense

2011 vs. 2010: Depreciation and Amortization expense increased by $5.6 million, or approximately 2.2%, when compared to 2010. This increase was primarily because of an overall increase in utility plant in service.

We expect depreciation and amortization expense to increase in 2012 as a result of an increase in utility plant in service related to the Glacier Hills Wind Park, which went in service in December 2011, and the Oak Creek Air Quality Control System (AQCS) project, which is scheduled to go in service in 2012.

2010 vs. 2009: Depreciation and Amortization expense decreased by $61.7 million, or approximately 19.7%, when compared to 2009. This decrease was primarily because of new depreciation rates that were implemented in connection with the 2010 PSCW rate case order. The new depreciation rates generally reflect longer lives for our utility assets.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached an agreement with our regulators to allow for the net gain on the sale to be used for the benefit of our customers. The majority of the benefits were returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it was amortized to the income statement as we issued bill credits to customers. When the bill credits were issued to customers, we transferred cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. All bill credits associated with the sale of Point Beach were applied to customers as of December 31, 2010, and as a result, the Amortization of Gain was zero during 2011 as compared to $198.4 million during 2010 and $230.7 million during 2009.

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). PWGS 1 and PWGS 2 were placed in service in July 2005 and May 2008, respectively. The common facilities associated with the Oak Creek expansion include the water intake system, which was placed in service in January 2009, the coal handling system, which was placed in service in November 2007, and other smaller assets. OC 1 and OC 2 were placed in service in February 2010 and January 2011, respectively.

The table below reflects:

- A full year's earnings for 2011, 2010 and 2009 for:
    - PWGS 1;
    - PWGS 2;
    - the coal handling system for the Oak Creek expansion; and
    - the water intake system for the Oak Creek expansion
- A full year's earnings for 2011 and approximately eleven months of earnings for 2010 for OC 1; and
- Approximately eleven and a half months of earnings for 2011 for 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.

	Year Ended December 31, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$ 104.7	$ 320.5	$ 9.9	$ 435.1
Operation and Maintenance Expense	0.8	4.6	8.3	13.7
Depreciation Expense	19.8	51.0	1.7	72.5
Operating Income (Loss)	$ 84.1	$ 264.9	$ (0.1)	$ 348.9

	Year Ended December 31, 2010			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$ 104.6	$ 203.3	$ 12.3	$ 320.2
Operation and Maintenance Expense	0.8	4.7	8.8	14.3
Depreciation Expense	19.8	32.0	1.7	53.5
Operating Income	$ 84.0	$ 166.6	$ 1.8	$ 252.4

	Year Ended December 31, 2009			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$ 104.8	$ 48.0	$ 10.3	$ 163.1
Operation and Maintenance Expense	0.9	5.2	7.7	13.8
Depreciation Expense	19.8	7.8	1.6	29.2
Operating Income	$ 84.1	$ 35.0	$ 1.0	$ 120.1

In 2012, we expect our non-utility energy segment to generate slightly higher operating income because OC 2 went into service on January 12, 2011 and changes in the depreciable lives of the plants.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2011 vs. 2010: Corporate and other affiliates had an operating loss of $6.4 million in 2011 compared with an operating loss of $6.0 million in 2010.

2010 vs. 2009: Corporate and other affiliates had an operating loss of $6.0 million in 2010 compared with an operating loss of $10.7 million in 2009. This change is primarily due to a reduction in other operation and maintenance expense.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2011	2010	2009
	(Millions of Dollars)		
AFUDC - Equity	$ 59.4	$ 32.5	$ 16.0
Gain on Property Sales	2.4	4.4	1.7
Other, net	0.9	3.3	10.8
Total Other Income and Deductions, net	$ 62.7	$ 40.2	$ 28.5

2011 vs. 2010: Other income and deductions, net increased by approximately $22.5 million, or 56.0%, when compared to 2010. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

During 2012, we expect to see a reduction in AFUDC - Equity with the completion of the Glacier Hills Wind park in December 2011 and the expected completion of the Oak Creek AQCS project by the end of 2012.

2010 vs. 2009: Other income and deductions, net increased by approximately $11.7 million, or 41.1%, when compared to 2009. This increase primarily relates to increased AFUDC - Equity related to the construction of the Oak Creek AQCS project.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2011	2010	2009
		(Millions of Dollars)	
Gross Interest Costs	$ 262.5	$ 258.7	$ 235.4
Less: Capitalized Interest	26.7	52.3	78.7
Interest Expense, net	$ 235.8	$ 206.4	$ 156.7

2011 vs. 2010: Our gross interest costs increased by $3.8 million, or 1.5%, during 2011, primarily because of higher average long-term debt balances as compared to 2010. In January 2011, we issued $420 million of long-term debt and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. In September 2011, we issued $300 million of long-term debt and used the net proceeds to repay short-term debt and for other general corporate purposes. In April 2011, we retired $450 million of long-term debt that matured, which partially offset the debt issuances. Our capitalized interest decreased by $25.6 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by $29.4 million, or 14.2%, as compared to 2010.

During 2012, we expect to see higher net interest expense because of a reduction in capitalized interest as a result of the Glacier Hills Wind Park project going in service in December 2011 and the expected completion of the Oak Creek AQCS project by the end of 2012.

2010 vs. 2009: Our gross interest costs increased by $23.3 million, or 9.9%, during 2010, primarily because of higher long-term debt balances compared to 2009. In February 2010, we issued $530 million of long-term debt in connection with the commercial operation of OC 1 and used the net proceeds to repay short-term debt incurred during construction. Our capitalized interest decreased by $26.4 million primarily because we stopped capitalizing interest on OC 1 when it was placed in service in February 2010. As a result, our net interest expense increased by $49.7 million, or 31.7%, as compared to 2009.

CONSOLIDATED INCOME TAX EXPENSE

2011 vs. 2010: Our effective tax rate applicable to continuing operations was 34.0% in 2011 compared to 35.5% in 2010. This reduction in our effective tax rate was primarily the result of increased AFUDC - Equity. For further information, see Note H -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2012 annual effective tax rate to be between 36% and 37%.

2010 vs. 2009: Our effective tax rate applicable to continuing operations was 35.5% in 2010 compared to 36.5% in 2009. This reduction in our effective tax rate was primarily the result of increased AFUDC - Equity and increased production activities tax deductions.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2011, 2010 and 2009:

Wisconsin Energy Corporation	2011	2010	2009
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$ 993.4	$ 810.4	$ 628.9
Investing Activities	$ (892.5)	$ (633.5)	$ (736.1)
Financing Activities	$ (111.3)	$ (172.6)	$ 95.7

Operating Activities

2011 vs. 2010: Cash provided by operating activities was $993.4 million during 2011, which was an increase of $183.0 million over 2010. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, higher deferred income tax benefits and the elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled $1,293.2 million during 2011 as compared to $680.4 million during 2010. The largest reduction in cash provided by operating activities related to our contributions to qualified benefit plans. During 2011, we contributed $277.4 million to our qualified benefit plans. We made no contributions to our qualified plans during 2010.

2010 vs. 2009: Cash provided by operating activities was $810.4 million during 2010, which was an increase of $181.5 million over 2009. This increase is primarily related to a $289.3 million contribution to our qualified benefit plans in 2009. No such contributions were made in 2010. This increase was partially offset by an increase in cash paid for taxes during 2010.

Investing Activities

2011 vs. 2010: Cash used in investing activities was $892.5 million during 2011, which was $259.0 million higher than 2010. This increase in cash used primarily reflects changes in restricted cash and increased capital expenditures. During 2011, our restricted cash increased by $37.2 million primarily because of the nuclear fuel settlement we received from the United States Department of Energy (DOE). During 2010, our restricted cash decreased by $186.2 million due to the release of restricted cash related to the Point Beach bill credits. See Nuclear Operations in this report for additional information regarding the settlement with the DOE. In addition, capital expenditures increased by approximately $32.6 million during 2011 as compared to 2010 primarily due to increased spending related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park in 2011 as compared to 2010.

The following table identifies capital expenditures by year:

Capital Expenditures	2011	2010	2009
	(Millions of Dollars)		
Utility	$ 792.2	$ 687.0	$ 547.0
We Power	31.2	109.3	253.2
Other	7.4	1.9	14.4
Total Capital Expenditures	$ 830.8	$ 798.2	$ 814.6

2010 vs. 2009: Cash used in investing activities was $633.5 million during 2010, which was $102.6 million lower than the same period in 2009 because of lower capital expenditures, lower investments in ATC and higher proceeds from asset sales. During 2010, we received $63 million of proceeds from the sale of Edison Sault Electric Company (Edison Sault).

Financing Activities

The following table summarizes our cash flows from financing activities:

	2011	2010	2009
	(Millions of Dollars)		
Net Increase in Debt	$ 265.4	$ 71.1	$ 263.2
Dividends on Common Stock	(242.0)	(187.0)	(157.8)
Common Stock Repurchased, Net	(139.5)	(65.7)	(12.6)
Other	4.8	9.0	2.9
Cash (Used in) Provided by Financing	$ (111.3)	$ (172.6)	$ 95.7

2011 vs. 2010: Cash used in financing activities was $111.3 million during 2011, compared to $172.6 million during 2010. During 2011, we issued a total of $720.0 million of long-term debt and retired $466.6 million of long-term debt. The net proceeds from the new issuance of debt were used to repay short-term debt and for other corporate purposes. For additional information on the debt issuances, see Note J -- Long-Term Debt and Capital Lease Obligations in the Notes to

Consolidated Financial Statements.

Our common stock dividends increased in 2011 as we raised our dividend rate by 30.0%. In January 2012, our Board of Directors approved an increase of approximately 15.4% in the quarterly common stock dividend.

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. 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. Through December 31, 2011, we repurchased approximately 3.2 million shares in the open market pursuant to this program at an average cost of $30.79 per share and a total cost of $100.0 million.

2010 vs. 2009: Cash used in financing activities during 2010 was $172.6 million, compared to $95.7 million of cash provided in 2009. During 2010, we issued a total of $530.0 million of long-term debt and retired $291.7 million of long-term debt. The net proceeds from the new issuance of debt were used to repay short-term debt incurred to finance the construction of OC 1 and for other corporate purposes.

Our common stock dividends increased in 2010 as we raised our dividend rate by 18.5%.

No new shares of Wisconsin Energy's common stock were issued in 2011, 2010 or 2009. During these years, our plan agents purchased, in the open market, 3.0 million shares at a cost of $93.9 million, 5.8 million shares at a cost of $156.6 million and 1.4 million shares at a cost of $29.6 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2011, 2010 and 2009, we received proceeds of $54.4 million, $90.9 million and $17.0 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 dividend reinvestment plan and various employee benefit plans.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

We anticipate meeting our capital requirements during 2012 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, 2011, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities that were entered into in December 2010. As of December 31, 2011, we had approximately $669.9 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2011, our maximum commercial paper outstanding was $717.3 million with a weighted-average interest rate of 0.25%. For additional information regarding our commercial paper balances during 2011, 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, 2011:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$ 450.0	$ 0.4	$ 449.6	December 2013
Wisconsin Electric	$ 500.0	$ 5.9	$ 494.1	December 2013
Wisconsin Gas	$ 300.0	$ —	$ 300.0	December 2013

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, 2011 and 2010, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view the Junior Notes:

	2011		2010	
Capitalization Structure	Actual	Adjusted	Actual	Adjusted
	(Millions of Dollars)			
Common Equity	$ 3,963.3	$ 4,213.3	$ 3,802.1	$ 4,052.1
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,646.9	4,396.9	4,405.4	4,155.4
Short-Term Debt	669.9	669.9	657.9	657.9
Total Capitalization	$ 9,310.5	$ 9,310.5	$ 8,895.8	$ 8,895.8
Total Debt	$ 5,316.8	$ 5,066.8	$ 5,063.3	$ 4,813.3
Ratio of Debt to Total Capitalization	57.1%	54.4%	56.9%	54.1%

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 Sheet as of December 31, 2011 and 2010 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 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 I -- 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, 2011, the repurchased bonds were still outstanding, but were reported as a reduction 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.

Bonus Depreciation Provisions

In December 2010, the President of the United States signed tax legislation extending the bonus depreciation rules to certain projects placed in service in 2010, 2011 and 2012. As a result of this extension, we recognized increased federal tax depreciation in 2010 and 2011 relating to assets placed in service during those years, including the Glacier Hills Wind Park, OC 1 and OC 2. In addition, we also anticipate an increase in tax depreciation in 2012 for assets placed in service during 2012, including the Oak Creek AQCS project. As a result of the increased tax depreciation in 2011 and 2012, we will not make federal income tax payments for 2011 and do not anticipate making federal income tax payments for 2012.

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 S&P and/or Baa3 at Moody's. As of December 31, 2011, we estimate that the collateral or the termination payments required under these agreements totaled approximately $184.5 million. Generally, collateral may be provided by a Wisconsin Energy guaranty, letter of credit or cash. We also have 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 November 2011, Moody's affirmed the ratings of Wisconsin Gas (commercial paper, P-1; senior unsecured, A2). In December 2011, Moody's affirmed the ratings of Wisconsin Energy (commercial paper, P-2; senior unsecured, A3; junior unsecured, Baa1), Wisconsin Electric (commercial paper, P-1; senior unsecured, A2), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes, A2) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured, A3). Moody's affirmed the stable ratings outlook assigned to each company.

In June 2011, S&P raised the rating of Wisconsin Energy's junior unsecured debt to BBB from BBB-, and affirmed the ratings of the remaining debt of Wisconsin Energy (commercial paper, A-2; senior unsecured, BBB+), Wisconsin Electric (commercial paper, A-2; senior unsecured, A-), Wisconsin Gas (commercial paper, A-2; 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 2011, after revising the ratings outlooks of each company from stable to positive in March 2011.

In June 2011, Fitch affirmed the ratings of Wisconsin Energy (commercial paper, F2; senior unsecured, A-; junior unsecured, BBB), Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1; senior unsecured, A+), ERGSS (senior notes, A+) and WECC (senior unsecured, 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 2012, 2013 and 2014 capital expenditures are as follows:

Capital Expenditures	2012	2013	2014
	(Millions of Dollars)		
Utility			
Renewable	$ 160.6	$ 24.4	$ —
Environmental	71.0	43.3	38.8
Base Spending	473.2	611.0	586.4
Total Utility	704.8	678.7	625.2
We Power	20.1	41.4	16.5
Other	15.3	9.3	1.7
Total	$ 740.2	$ 729.4	$ 643.4

Base spending primarily 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: During 2012, we expect to continue to repurchase our common stock under the share repurchase program approved by the Board on May 5, 2011, and to pay the increased quarterly dividend of $0.30 per share approved by the Board in January 2012.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately $1.5 billion as of December 31, 2011. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2011, we contributed $236.4 million to our qualified pension plans and $41.0 million to our qualified Other Post-Retirement Employee Benefit (OPEB) plans. We did not make contributions to the plans during 2010 as they were adequately funded. 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 G -- Variable Interest Entities and Note O -- Guarantees 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, 2011:

	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)	$ 8,245.2	$ 273.1	$ 1,181.6	$ 891.1	$ 5,899.4
Capital Lease Obligations (c)	295.1	38.9	82.3	88.6	85.3
Operating Lease Obligations (d)	63.3	16.3	10.4	7.6	29.0
Purchase Obligations (e)	13,473.1	974.1	1,446.1	1,072.4	9,980.5
Other Long-Term Liabilities (f)	111.4	110.3	0.8	0.3	—
Total Contractual Obligations	$ 22,188.1	$ 1,412.7	$ 2,721.2	$ 2,060.0	$ 15,994.2

(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). For the purpose of determining our contractual obligations and commercial commitments only, we assumed the Junior Notes would be retired in 2017 with the proceeds from the issuance of qualifying securities pursuant to the terms of the Replacement Capital Covenant (RCC).

(c) Capital Lease Obligations of Wisconsin Electric for power purchase commitments.

(d) Operating Lease Obligations for power purchase commitments and vehicle 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.

(f) Other Long-Term Liabilities includes the expected 2012 supplemental executive retirement plan obligation. For additional information on employer contributions to our benefit plans, see Note N -- Benefits in the Notes to Consolidated Financial Statements.

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 H -- 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. We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. 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, 2011, our regulatory assets totaled $1,265.7 million and our regulatory liabilities totaled $915.9 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. Effective January 1, 2011, the PSCW implemented new fuel rules which 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 Rules.

Natural Gas Costs: Higher natural gas costs 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 November 2011 rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs through December 31, 2012. 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 2011, 2010 and 2009, 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, 2011. 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, 2011 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2011, we had $669.9 million of commercial paper outstanding with a weighted average interest rate of 0.27% 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 $8.2 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, 2011 was approximately:

Wisconsin Energy Corporation	Millions of Dollars	
Pension trust funds	$	1,262.5
Other post-retirement benefits trust funds	$	255.4

For 2012, the expected long-term rate of return on plan assets 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. The following table identifies certain key items related to the units:

Unit Name	In Service	Cash Costs (a)
PWGS 1	July 2005	$333 million
PWGS 2	May 2008	$331 million
OC 1	February 2010	$1,354 million
OC 2	January 2011	$662 million

(a) Cash costs represent actual and current projected costs, excluding capitalized interest. Approximate costs for OC 1 and OC 2 include the cost of the settlement agreement with Bechtel adjusted for our ownership percentage.

We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2 and OC 1 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. Wisconsin Electric is recovering the lease payments associated with OC 2 as authorized by the PSCW and FERC, and has requested authorization from the MPSC in the rate case filed in July 2011. 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. The interest component of the return has been determined at rates in effect at the time of commercial operation.

Background: The PSCW issued orders granting Certificates of Public Convenience and Necessity (CPCN) for the construction of the PWGS and the Oak Creek expansion in 2002 and 2003, respectively.

PWGS consists of two natural gas-fired combined cycle generating units on the site of Wisconsin Electric's former Port Washington Power Plant, the natural gas lateral to supply the new plant, and the transmission system upgrades required of ATC. PWGS 1 and PWGS 2 were completed within the PSCW approved cost parameters and were placed in service in July 2005 and May 2008, respectively.

The Oak Creek expansion consists of two coal-fired generating units located adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. OC 1 and OC 2 were placed into service on February 2, 2010 and January 12, 2011, respectively. The PSCW set the total cost for the two units at $2.191 billion. We estimate that the final cost of the Oak Creek expansion is approximately $181 million, or 8.3%, over the amount initially approved by the PSCW, of which our share is approximately $154 million. The additional amount includes the amounts payable to Bechtel Power Corporation (Bechtel) pursuant to the Settlement Agreement. The order approving the Oak Creek expansion provides for recovery of excess costs of up to 5% of the total project, subject to a prudence review by the PSCW. Costs above the 5% cap would also be included in lease payments and recovered from customers if the PSCW finds that such costs were prudently incurred and were the result of force majeure conditions, an excused event and/or event of loss. In addition, the leases provided for a guaranteed in-service date of September 29, 2009 for OC 1 and September 29, 2010 for OC 2, and imposed liquidated damages of $250,000 per day, of which ERGSS' share is approximately $208,350 per day, for failure to achieve the guaranteed in-service date unless the delays resulted from force majeure conditions or an excused event. In light of the weather delays incurred on the project and other factors, we expect to request authorization from the PSCW to recover all costs associated with the units and to grant relief from liquidated damages.

ERGSS was entitled to receive its share of $250,000 per day from Bechtel under the contract with Bechtel for each day Bechtel failed to achieve the guaranteed in-service dates of September 29, 2009 and September 29, 2010, unless the delays resulted from force majeure conditions or excused events. Pursuant to the terms of the Settlement Agreement and a change order signed concurrent with the turnover of OC 2, Bechtel was granted total schedule relief of 120 days for OC 1 and 81 days for OC 2. Therefore, Bechtel was responsible for 5 days of liquidated damages for OC 1 and 23 days for OC 2. All liquidated damages collected are for the benefit of Wisconsin Electric's customers. Although we anticipate the PSCW will agree that the excused delays were caused by force majeure and other conditions, there is no guarantee that it will grant ERGSS the same schedule relief.

For information regarding the Settlement Agreement, see Oak Creek Construction Contract in Note R -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Lease Terms: The PSCW approved the lease agreements and related documents under which Wisconsin Electric will staff, operate and maintain PWGS 1, PWGS 2, OC 1 and OC 2. Key terms of the leased generation contracts are as follows:

PWGS 1 & PWGS 2

- Initial lease term of 25 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 25 year period on a mortgage basis amortization schedule;
- Imputed capital structure of 53% equity, 47% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Fixed construction cost of PWGS 1 and PWGS 2 at $309.6 million and $280.3 million (2001 dollars) subject to escalation at the GDP inflation rate;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the order, which do not include the key financial terms.

OC 1 & OC 2

- Initial lease term of 30 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 30 year period on a mortgage basis amortization schedule;
- Imputed capital structure of 55% equity, 45% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the order, which do not include the key financial terms.

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, we estimate that approximately 86% of our electric revenues are regulated by the PSCW, 7% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. 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/.

2012 Wisconsin Rate Case: On May 26, 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 results in no increase in 2012 base rates for our customers. In 2012, Wisconsin Electric and Wisconsin Gas would seek base rate increases to be effective in 2013. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that:

- 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.
- Authorizes Wisconsin Electric to reopen the rate proceeding in 2012 to address, for rates effective in 2013, all issues set aside during 2012, including the determination of the final approved construction costs for the Oak Creek expansion.
- Schedules a proceeding to establish a 2012 fuel cost plan.

On October 6, 2011, the PSCW approved our proposal as filed. We received a final written order from the PSCW on November 3, 2011. For information related to the proceeding to establish a 2012 fuel cost plan, see 2012 Fuel Recovery Request below. We expect to initiate a traditional rate case filing in early 2012 for new electric, gas and steam rates to be effective in January 2013.

2012 Michigan Rate Case: On July 5, 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. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. Therefore, in January 2012, we implemented a $5.7 million interim electric base rate increase. This increase is 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. Therefore, the total self-implementation was $7.7 million. A final decision from the MPSC is expected in July 2012.

2010 Wisconsin Rate Case: In March 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric initially asked the PSCW to approve a rate increase for its Wisconsin retail electric customers of approximately $76.5 million, or 2.8%, and a rate increase for its natural gas customers of approximately $22.1 million, or 3.6%. In addition, Wisconsin Electric requested increases of approximately $1.4 million, or 5.8%, and approximately $1.3 million, or 6.8%, for its Milwaukee Downtown (Valley) steam utility customers and Milwaukee County steam utility customers, respectively. Wisconsin Gas asked the PSCW to approve a rate increase for its natural gas customers of approximately $38.9 million, or 4.6%.

In July 2009, Wisconsin Electric filed supplemental testimony with the PSCW updating its rate increase request for retail electric customers to reflect the impact of lower sales as a result of the decline in the economy. The effect of the change resulted in Wisconsin Electric increasing its request from $76.5 million to $126.0 million.

In December 2009, the PSCW authorized rate adjustments related to Wisconsin Electric's and Wisconsin Gas' requests to increase electric, natural gas and steam rates. The PSCW approved the following rate adjustments:

- An increase of approximately $85.8 million (3.35%) in retail electric rates for Wisconsin Electric, which was partially offset by bill credits in 2010 and included a decrease in base fuel revenues of approximately $111.0 million, or a fuel rate component decrease of 13.8%;
- 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%.
The PSCW also made, among others, the following determinations:

- New depreciation rates were incorporated into the new base rates approved in the rate case;
- Certain regulatory assets that were scheduled to be fully amortized over four years are instead being amortized over eight years; and
- Wisconsin Electric will continue to receive AFUDC on 100% of Construction Work in Progress for the environmental control projects at our Oak Creek Power Plant and at Edgewater Generating Unit 5, and on the Glacier Hills Wind Park. Wisconsin Electric sold its interest in Edgewater Generating Unit 5 in March 2011 and completed construction of Glacier Hills in December 2011.

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. On September 3, 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. Wisconsin Electric requested an increase in 2011 Wisconsin retail electric rates of $38.4 million, or 1.4%, related to the increase in 2011 monitored fuel costs as compared to the level of monitored fuel costs then embedded in rates. In December 2010, Wisconsin Electric reduced its request by approximately $5.2 million. Adjustments by the PSCW reduced the request by an additional $7.8 million. The PSCW issued its final decision, which increased annual Wisconsin retail rates by $25.4 million effective April 29, 2011. The net increase was being 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 December 2009, the MPSC approved Wisconsin Electric's modified self-implementation plan to increase electric rates in Michigan by approximately $12 million, effective upon commercial operation of OC 1, which occurred on February 2, 2010. On July 1, 2010, the MPSC issued the final order, approving an additional increase of $11.5 million effective July 2, 2010. The combined total increase is $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, which we expect to occur in the first quarter of 2012.

Limited Rate Adjustment Requests

2012 Fuel Recovery Request: On August 3, 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 are projected higher coal, coal transportation and purchased power costs. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. On January 5, 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 regarding the storage of spent nuclear fuel, resulting in no change in customer rates.

2010 Fuel Recovery Request: In February 2010, Wisconsin Electric filed a $60.5 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel and purchased power costs was driven primarily by increases in the price of natural gas compared to the forecasted prices included in the 2010 PSCW rate case order, changes in the timing of plant outages and increased MISO costs. Effective March 25, 2010, the PSCW approved an annual increase of $60.5 million in Wisconsin retail electric rates on an interim basis. On April 28, 2011, the PSCW approved the final increase with no changes.

2009 Fuel Order: Under the fuel rules in effect in 2008 and 2009, a Wisconsin utility could request an emergency rate increase if projected costs fell outside of a prescribed range of costs which was plus or minus 2% of the fuel rate approved in a general rate proceeding.

In March 2008, Wisconsin Electric filed a request for an emergency rate increase with the PSCW to recover forecasted increases in fuel and purchased power costs. The PSCW authorized a total increase of $118.9 million. In April 2009, Wisconsin Electric filed a request with the PSCW to decrease annual Wisconsin retail electric rates by $67.2 million because it forecasted that its monitored fuel cost for 2009 would fall outside the range prescribed by the PSCW and would be less than the fuel cost reflected in then authorized rates. The PSCW approved this request on an interim basis with rates effective May 1, 2009.

The PSCW staff audited the fuel costs for the year 2009 to determine whether Wisconsin Electric collected excess revenues as a result of the fuel surcharges that were in place in 2008 and 2009. Under the fuel rules, if a utility collects excess revenues in a year in which it implemented an emergency fuel surcharge, it is required to refund to customers the over-collected fuel surcharge revenue up to the amount of the excess revenues. In February 2011, the PSCW closed out its review of this matter and determined that Wisconsin Electric did not collect any excess revenues.

Other Utility Rate Matters

Oak Creek Air Quality Control System Approval: 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, and we expect the installation to be completed during 2012. We currently expect the cost of completing this project to be approximately $750 million ($900 million including AFUDC). The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree with the United States Environmental Protection Agency (EPA).

Wisconsin Fuel Rules: Embedded within Wisconsin Electric's base rates is an amount to recover fuel costs. New fuel rules adopted in December 2010 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. Fuel cost plans approved by the PSCW after January 1, 2011 are subject to the new rules. The deferred fuel costs are subject to an excess revenues test.

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 the state. 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, 2011, we had $118.3 million of unrecovered transmission costs. The escrow accounting treatment has been discontinued as our 2008 and 2010 PSCW rate orders have provided for recovery of these costs.

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. As part of its January 2010 rate order, the PSCW approved changes to the GCRMs. The GCRMs now 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. The modified one for one is the same method used by the other utilities in Wisconsin.

Depreciation Rates: In January 2009, we filed a depreciation study with the PSCW, proposing new depreciation rates that would reduce annual depreciation expense by approximately $55 million. The PSCW approved the depreciation study and the new depreciation rates began on January 1, 2010. We estimate that the new depreciation rates did not have a material impact on earnings because the new depreciation rates were considered when the PSCW set our 2010 electric and gas rates.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin revised the requirements for renewable energy generation by enacting 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, 2011, 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 establishes 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 is in the process of constructing approximately 50 MW of biomass fueled generation. With the commercial operation of the Glacier Hills Wind Park in December 2011 and assuming the biomass project is completed on schedule, we expect to be in compliance with Act 141 through the year 2016. To remain in compliance with Act 141, we would need to construct or contract for the equivalent of approximately 400 MW of additional wind generating capacity beyond 2016. See Renewable Energy Portfolio discussion below for additional information regarding the development of renewable energy generation.

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. Prior to Act 141, there had been no agreement on how to determine compliance with the Energy Priorities law, which provides that it is the policy of the PSCW, to the extent it is cost-effective and technically feasible, to consider the following options in the listed order when reviewing energy-related applications: (1) energy conservation and efficiency, (2) noncombustible renewable energy resources, (3) combustible renewable energy resources, (4) natural gas, (5) oil or low sulfur coal and (6) high sulfur coal and other carbon-based fuels.

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 1.5% of utilities' annual operating revenues be used to fund these programs in 2011. The funding required by Act 141 decreased to 1.2% of annual operating revenues in 2012.

Public Act 295 enacted in Michigan calls for the implementation of a renewable portfolio standard 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.

Renewable Energy Portfolio: The Blue Sky Green Field wind farm project, which has 88 turbines with an installed capacity of 145 MW, commenced commercial operation in May 2008. The Glacier Hills Wind Park, which has 90 turbines with an installed capacity of 162 MW, commenced commercial operation in December 2011. We estimate that the final cost of the Glacier Hills Wind Park will be approximately $355 million.

We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced on June 27, 2011. We currently expect to invest between $245 million and $255 million, excluding AFUDC, in the plant and we expect the plant to be completed during the fall of 2013.

Pursuant to the National Defense Authorization Act (NDAA), which was passed in December 2011, utilities are now able to elect to receive a cash grant for renewable energy projects without the effect of normalization for income tax purposes. We are currently evaluating the impact of the NDAA on whether we pursue federal production tax credits or grants for certain of our renewable generation projects.

ELECTRIC SYSTEM RELIABILITY

In response to customer demand for higher quality power required by modern equipment, we are evaluating and updating our electric distribution system. We are taking steps to reduce the likelihood of outages by upgrading substations and rebuilding lines to upgrade voltages and reliability. These improvements, along with better technology for analysis of our existing system, better resource management to speed restoration and improved customer communication, are near-term efforts to enhance our current electric distribution infrastructure. For the long-term, we have developed a distribution system asset management strategy that requires increased levels of automation of both substations and line equipment to consistently provide the level of reliability needed for a digital economy.

We had adequate capacity to meet all of our firm electric load obligations during 2011 and 2010. All of our generating plants performed well 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 all of our firm load obligations during 2012. However, extremely hot weather, unexpected equipment failure or unavailability 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 are continuing to pursue a proactive strategy to manage our environmental compliance obligations, including: (1) developing additional sources of renewable electric energy supply; (2) reviewing water quality matters such as discharge limits and cooling water requirements and implementing improvements to our cooling water intake systems as needed; (3) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (4) implementing a Consent Decree with the EPA to reduce emissions of SO_2 and NO_x by more than 65% by 2013; (5) continuing the beneficial use of ash and other solid products from coal-fired generating units; and (6) conducting 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 EPA, in which it agreed to significantly reduce air emissions from certain of its coal-fired generating facilities. The U.S. District Court for the Eastern District of Wisconsin approved the amended Consent Decree and entered it in October 2007. 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 scheduled to begin service in 2012. For further information, see Note R -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

8-hour Ozone Standard: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 8-hour ozone ambient air quality standard. The EPA has since redesignated three of these counties - Kewaunee, Manitowoc and Door - in attainment with the standard, and has made a finding that the remaining seven counties have achieved attainment with the standard. The EPA has stated, however, that Wisconsin must revise a portion of its State Implementation Plan (SIP) relating to volatile organic compounds, which do not apply to our facilities, before these seven counties can be formally redesignated. Pending redesignation, we will continue to be subject to more stringent permitting standards for new or revised facilities in the affected seven counties.

In March 2008, the EPA announced its decision to further lower the 8-hour ozone standard, and in January 2010, the EPA proposed to lower that standard further. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard until 2013, and the EPA began implementing the 2008 standard. The EPA has stated that it plans to finalize the designations under the 2008 ozone standard by May 31, 2012. The EPA has preliminarily designated Waukesha, Washington, Milwaukee and Racine Counties as being in attainment with the standard. Currently, the only counties in Wisconsin that are proposed for non-attainment are Kenosha and Sheboygan Counties.

Fine Particulate Standard: In December 2006, a more restrictive federal standard for fine particulate matter ($PM_{2.5}$) became effective; however, in February 2009, the U.S. Court of Appeals for the D.C. Circuit issued a decision on the revised standard and remanded it back to the EPA for revision. In October 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the 2006 daily standard for $PM_{2.5}$. Wisconsin has submitted a request to the EPA to redesignate these three counties as being in attainment with the 2006 standard. If the EPA denies this request, Wisconsin will be required to develop a SIP and submit it to the EPA for approval, and will need to implement actions to reach attainment in the 2014-2019 time period. The impact of future SIP requirements on our operations, if any, cannot be determined at this time, particularly given the EPA's continued efforts to revise the 2006 standard in light of the D.C. Circuit Court's decision.

In a related matter, in August 2010, the Wisconsin Natural Resources Board adopted rules to reflect changes made by the EPA in their regulations regarding the regulation of $PM_{2.5}$. The rule became effective on January 1, 2011. $PM_{2.5}$ is proposed to be included as a pollutant used to determine whether a facility is a major source of air pollution. Additionally, any modifications to an existing facility that would result in increases in $PM_{2.5}$ emissions could trigger pre-construction permitting requirements, including requirements to control emissions to levels which represent best available control technology or lowest achievable emission rate.

Sulfur Dioxide Standard: In June 2010, the EPA issued new hourly SO_2 National Ambient Air Quality Standards that became effective in August 2010. These standards, as modified, represent a significant change from the previous SO_2 standards. The new standards, among other things, require attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data.

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 standards remain in place, we believe that we would not need to make significant capital expenditures at the majority of our generation units because of prior investments in pollution control equipment and technology. However, we believe that the new standards may require us to retire our Presque Isle Power Plant in the Upper Peninsula of Michigan early because the cost of installing new pollution control equipment at this plant may exceed other alternatives we are currently studying, which include investing in the transmission system in that region, adding new air quality controls and possible shared ownership of the Presque Isle Power Plant. The new standards 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 coal-fired generation facilities until final attainment designations are made and until any potential additional rules are adopted.

Mercury and Other Hazardous Air Pollutants: On December 16, 2011, the EPA issued the final utility Maximum Achievable Control Technology (MACT) rule (referred to as the 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. While we are continuing to evaluate the impact of the rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with the rule, we currently estimate our cost to comply with this rule will be approximately $16 million. Based upon our review, the Valley Power Plant (VAPP) and Presque Isle Power Plant may require additional modifications. In addition, we believe that our clean air strategy, including the environmental upgrades that have already been constructed and that are currently under construction at our other plants, positions those plants well to meet the rule's requirements.

Cross-State Air Pollution Rule: On August 8, 2011, the EPA issued a final rule, 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 scheme. On October 14, 2011, the EPA published proposed revisions to CSAPR, which if finalized, would delay the implementation date for certain penalty provisions that could potentially impact the Presque Isle Power Plant and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with these proposed revisions, however, the Presque Isle Power Plant 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 on December 30, 2011, the U.S. Court of Appeals for the District of Columbia granted a motion to stay CSAPR pending judicial review of the rule. While the CSAPR is stayed, the CAIR will remain in effect. We are unable to predict the outcome of this review at this time.

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 into our capital and operation and maintenance costs.

Clean Air Visibility Rule: The EPA issued the Clean Air Visibility Rule (CAVR) 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 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.

Pursuant to the rule, in July 2011, Wisconsin proposed a draft SIP for public comment. Michigan submitted a complete SIP to the EPA, but on December 30, 2011, the EPA proposed to disapprove the portion of the Michigan SIP that related to utility reductions of NO_x and SO_2 that were expected to occur under CAIR because the EPA had replaced the CAIR program with CSAPR. In this same proposal, the EPA proposed a partial Federal Implementation Plan (FIP) for Michigan that would rely on CSAPR for utility reductions of NO_x and SO_2. Issuance of a final partial FIP to Michigan may not occur while judicial review of CSAPR is pending. The EPA did not take action on the other portions of the Michigan SIP submittal.

The BART rules completed by Wisconsin and Michigan, which cover one aspect of the CAVR regulations, are partially based on utility reductions of NO_x and SO_2 that were expected to occur under CAIR. While the EPA has expressed its intention to allow states to consider utility reductions of NO_x and SO_2 expected under CSAPR in its Regional Haze SIPs, we will not be able to determine final impacts of these rules until judicial review of CSAPR is completed and any subsequent rulemaking activities required as result of that review 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. Our emissions in future years will continue to be influenced by several actions completed, planned or underway, including:

- Repowering the Port Washington Power Plant from coal to natural gas-fired combined cycle units.
- Adding coal-fired units as part of the Oak Creek expansion that are the most thermally efficient coal units in our system.
- Increasing investment in energy efficiency and conservation.
- Adding renewable capacity and promoting increased participation in the Energy for Tomorrow® renewable energy program.
- Retirement of coal units 1-4 at the Presque Isle Power Plant.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The regulation of greenhouse gas emissions through legislation and regulation has been, and continues to be, a focus of the President and his administration. Although legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards failed to pass in the U.S. Congress, we expect such legislation to be considered in the future. Any mandatory restrictions on our Carbon Dioxide (CO_2) emissions that may be adopted by Congress or Wisconsin's or Michigan's legislature could result in significant compliance costs that could affect future results of operations, cash flows and financial condition. While climate legislation has yet to be adopted, the EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the Clean Air Act (CAA). These regulations are expected to impact our ability to do maintenance or modify our existing facilities, and permit new facilities. Depending on the extent of rate recovery and other factors, these rules could have a material adverse impact on our financial condition.

Beginning with 2010, we are required to report our CO_2 equivalent emissions from our electric generating facilities to the EPA under its Mandatory Reporting of Greenhouse Gases rule. For 2010, we reported CO_2 equivalent emissions of approximately 20.9 million metric tonnes to the EPA. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 equivalent emissions of approximately 22.6 million metric tonnes to the EPA for 2011. 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 2010, we reported approximately 9.0 million metric tonnes of CO_2 to the EPA related to our distribution and sale of natural gas. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 emissions of approximately 9.6 million metric tonnes to the EPA for 2011.

Valley Power Plant: We are exploring various options at VAPP in connection with the new environmental regulations, including converting it from a coal-fired plant to a natural gas-fired plant. For further information, see Note R -- 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 on March 28, 2011, which must be finalized by July 27, 2012 in accordance with a judicial settlement entered into by the EPA. Once the rule is final, 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 Presque Isle Power Plant 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.

Steam Electric Effluent Guidelines: The federal Steam Electric Effluent guidelines, which regulate waste water discharges, are under review by the EPA. These rules govern discharges of waste water from our power plant processes. The EPA rules are expected to be finalized in 2014. After the promulgation of final rules, it is expected that the Wisconsin Department of Natural Resources (WDNR) will need to modify Wisconsin's rules. The existing Wisconsin state rules for waste water discharge are very stringent, and therefore, the systems that have been installed at the Pleasant Prairie Power Plant and the Oak Creek Power Plant use advanced technology. We are unable to determine the impact, if any, of these rules on our facilities at this time.

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 June 2010, the EPA issued draft rules for public comment proposing two alternative rules for regulating coal combustion products. One of the proposed rules classifies the materials as hazardous waste. We submitted comments on the proposed rules in November 2010. The EPA also issued a Notice of Data Availability (NODA) in October 2011, and we submitted comments on the NODA in November 2011. 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, and finalized a Non-Hazardous Secondary Materials Rule. Both of these rules have the potential to negatively affect our ability to reburn coal ash from power plants and landfills. Presently, we have a successful program for reburning coal ash to recover energy and produce a usable fly ash product for the concrete industry.

Manufactured Gas Plant Sites: We are voluntarily reviewing and addressing environmental conditions at a number of former manufactured gas plant sites. For further information, see Note R -- 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 R -- Commitments and Contingencies in the Notes to Consolidated Financial

Statements.

LEGAL MATTERS

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of the Employee Retirement Income Security Act of 1974 (ERISA) and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. We do not anticipate further charges as a result of the settlement, other than certain process-related costs we expect to incur to implement the settlement. We expect the court to provide final approval of the settlement agreement in April 2012, and to pay additional benefits to class members promptly after receiving this approval.

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 continue to make 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." In December 2008, a stray voltage lawsuit was filed against Wisconsin Electric. This lawsuit was settled in May 2011. This settlement did not have a material effect on our financial condition or results of operations. Another stray voltage lawsuit was filed against Wisconsin Electric in January 2011, but was dismissed without prejudice by the court on February 21, 2012. We continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Used Nuclear Fuel Storage and Disposal: During Wisconsin Electric's ownership of Point Beach, Wisconsin Electric was authorized by the PSCW to load and store sufficient dry fuel storage containers to allow Point Beach Units 1 and 2 to operate to the end of their original operating licenses, but not to exceed the original 48-canister capacity of the dry fuel storage facility. The original operating licenses were set to expire in October 2010 for Unit 1 and in March 2013 for Unit 2 before they were renewed and extended by the United States Nuclear Regulatory Commission in December 2005.

Temporary storage alternatives at Point Beach are necessary until the DOE takes ownership of and permanently removes the used fuel as mandated by the Nuclear Waste Policy Act of 1982, as amended in 1987. The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of such waste and fuel. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach, a responsibility for which Wisconsin Electric paid a total of $215.2 million into the Nuclear Waste Fund over the life of its ownership of Point Beach.

In August 2000, the United States Court of Appeals for the Federal Circuit ruled in a lawsuit brought by Maine Yankee and Northern States Power Company that the DOE's failure to begin performance by January 31, 1998 constituted a breach of the Standard Contract, providing clear grounds for filing complaints in the Court of Federal Claims. Consequently, Wisconsin Electric filed a complaint in November 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted Wisconsin Electric's motion for summary judgment on liability. The Court held a trial during September and October 2007 to determine damages. In December 2009, the Court ruled in favor of Wisconsin

Electric, granting us more than $50 million in damages. In February 2010, the DOE filed an appeal. 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, is being returned to customers as part of the PSCW's approval of our 2012 fuel recovery request and the MPSC's approval of our interim order for the 2012 Michigan rate case.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large Regional Transmission Organizations (RTO), which will 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 which potentially affects our Michigan operations.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. Due to many factors, including relatively competitive electric rates charged by the state's electric utilities, 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: Our Michigan retail customers are allowed to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We have maintained our generation capacity and distribution assets and provide regulated service as we have in the past. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Competition and customer switching to alternative suppliers in our service territories in Michigan has been limited. With the exception of general inquiries, no alternate supplier activity has occurred in our service territories in Michigan. We believe that this lack of alternate supplier activity reflects our small market area in Michigan, our competitive regulated power supply prices and a general lack of interest in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Electric Transmission 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.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of Revenue Sufficiency Guarantee (RSG) charges. FERC ordered MISO to resettle all affected transactions retroactive to the commencement of the energy market. In October 2006 and March 2007, we received additional rulings from FERC on these issues. FERC's rulings have been challenged by MISO and numerous other market participants. In July 2007, MISO commenced with the resettlement of the market in response to the orders. The resettlement was completed in January 2008 and resulted in a net cost increase of $7.8 million to us. Several entities filed formal complaints with FERC on the assessment of these charges. We filed in support of these complaints.

In November 2007, FERC issued another RSG order related to the rehearing requests previously filed. This order provided a clarification that was contrary to how MISO implemented the last resettlement. Once again, several parties, including Wisconsin Electric, filed for rehearing and/or clarification with FERC.

In addition, FERC ruled on the formal complaints filed by other entities in August 2007. FERC ruled that the current RSG cost allocation methodology may be unjust and unreasonable and established a refund effective date of August 10, 2007. MISO was ordered to file a new cost allocation methodology by March 2008. MISO filed new tariff language which indicated the new cost allocation methodology cannot be applied retroactively. We extended our previous rehearing/clarification request to include the timeframe from the established refund date through March 2008. In September 2008, FERC set a paper hearing for the formal complaints filed in 2007. FERC ruled on the outstanding rehearing/clarification requests and formal complaints in November 2008. FERC's ruling ordered the resettlements to begin from the date the MISO Energy Markets commenced in order to correct the RSG cost allocation methodology. Additionally, the order also set a new RSG cost allocation effective August 10, 2007. However, numerous entities filed rehearing requests in objection of these rulings. Although MISO requested a postponement of the resettlements until the matter is resolved, the resettlement commenced in March 2009. In May 2009, FERC issued an order denying rehearing on substantive matters for the rate period beginning August 10, 2007. However, FERC modified the effective date of that rate to November 10, 2008, and ordered MISO to cease the ongoing resettlement and to reconcile all invoices and payments therein. Similarly, in June 2009, FERC dismissed rehearing requests, but waived refunds for the period April 25, 2006 through November 4, 2007. FERC also stated for the first time that it was waiving refunds for the period April 1, 2005 through April 24, 2006. We, along with others, have sought rehearing and/or appeal of the FERC's May and June 2009 determinations pertaining to refunds. In addition, there are contested compliance matters pending FERC review. The net effects of FERC's rulings 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 was completed for the period of June 1, 2011 through May 31, 2012. The resulting ARR valuation and the secured FTRs should mitigate our transmission congestion risk for that period.

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 is presently on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

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.

International Financial Reporting Standards: During 2009, the SEC announced a "roadmap" for the potential use by U.S. registrants of IFRS instead of GAAP. The SEC issued a Work Plan to consider specific areas and factors relevant to a determination of whether, when and how the current financial reporting system for U.S. registrants should be transitioned to a system incorporating IFRS. Working under the assumption that the SEC would make a decision in 2011, the Work Plan anticipated that the first time U.S. registrants would report under IFRS would be approximately 2015 or 2016. Since the release of the Work Plan, the SEC has issued several papers discussing the incorporation of IFRS into the U.S. financial reporting system and held a roundtable discussion, but has yet to make a determination regarding IFRS. To the extent the SEC determines to adopt IFRS, if at all, we are currently unable to determine when we would be required to begin using IFRS.

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, 2011, we had $1,265.7 million in regulatory assets and $915.9 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	$ 4.7
0.5% decrease in expected rate of return on plan assets	$ 5.7

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	$	2.3
0.5% decrease in health care cost trend rate in all future years	$	(3.1)
0.5% decrease in expected rate of return on plan assets	$	1.2

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 2011 of approximately $4.4 billion included accrued utility revenues of $252.7 million as of December 31, 2011.

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

	2011	2010	2009
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 4,486.4	$ 4,202.5	$ 4,100.9
Operating Expenses			
Fuel and purchased power	1,169.7	1,099.9	1,059.7
Cost of gas sold	728.7	751.5	912.0
Other operation and maintenance	1,256.8	1,327.5	1,246.1
Depreciation and amortization	330.2	305.6	343.0
Property and revenue taxes	113.7	106.0	110.5
Total Operating Expenses	3,599.1	3,590.5	3,671.3
Amortization of Gain	—	198.4	230.7
Operating Income	887.3	810.4	660.3
Equity in Earnings of Transmission Affiliate	62.5	60.1	59.1
Other Income and Deductions, net	62.7	40.2	28.5
Interest Expense, net	235.8	206.4	156.7
Income from Continuing Operations Before Income Taxes	776.7	704.3	591.2
Income Tax Expense	263.9	249.9	215.5
Income from Continuing Operations	512.8	454.4	375.7
Income from Discontinued Operations, Net of Tax	13.4	2.1	6.7
Net Income	$ 526.2	$ 456.5	$ 382.4
Earnings Per Share (Basic)			
Continuing Operations	$ 2.20	$ 1.94	$ 1.61
Discontinued Operations	0.06	0.01	0.03
Total Earnings Per Share (Basic)	$ 2.26	$ 1.95	$ 1.64
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.18	$ 1.92	$ 1.59
Discontinued Operations	0.06	0.01	0.03
Total Earnings Per Share (Diluted)	$ 2.24	$ 1.93	$ 1.62
Weighted Average Common Shares Outstanding (Millions)			
Basic	232.6	233.8	233.8
Diluted	235.4	236.7	235.9

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2011	2010
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 12,977.7	$ 11,590.8
Accumulated depreciation	(3,797.8)	(3,624.0)
	9,179.9	7,966.8
Construction work in progress	921.3	1,569.9
Leased facilities, net	59.2	64.8
Net Property, Plant and Equipment	10,160.4	9,601.5
Investments		
Equity investment in transmission affiliate	349.7	330.5
Other	43.6	45.8
Total Investments	393.3	376.3
Current Assets		
Cash and cash equivalents	14.1	24.5
Restricted cash	45.5	8.3
Accounts receivable, net of allowance for doubtful accounts of $61.7 and $58.1	349.4	344.6
Income taxes receivable	155.1	83.7
Accrued revenues	252.7	280.3
Materials, supplies and inventories	382.0	379.1
Prepayments	140.3	125.6
Other	87.1	85.0
Total Current Assets	1,426.2	1,331.1
Deferred Charges and Other Assets		
Regulatory assets	1,238.7	1,090.1
Goodwill	441.9	441.9
Other	201.6	218.9
Total Deferred Charges and Other Assets	1,882.2	1,750.9
Total Assets	$ 13,862.1	$ 13,059.8

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

	2011	2010
	(Millions of Dollars)	
Capitalization		
Common equity	$ 3,963.3	$ 3,802.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,614.3	3,932.0
Total Capitalization	8,608.0	7,764.5
Current Liabilities		
Long-term debt due currently	32.6	473.4
Short-term debt	669.9	657.9
Accounts payable	325.7	315.4
Accrued payroll and vacation	105.9	88.3
Other	230.4	186.1
Total Current Liabilities	1,364.5	1,721.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	902.0	883.8
Deferred income taxes - long-term	1,696.1	1,154.8
Deferred revenue, net	754.5	805.5
Pension and other benefit obligations	222.7	353.2
Other long-term liabilities	314.3	376.9
Total Deferred Credits and Other Liabilities	3,889.6	3,574.2
Commitments and Contingencies (Note R)		
Total Capitalization and Liabilities	$ 13,862.1	$ 13,059.8

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

	2011	2010	2009
	(Millions of Dollars)		
Operating Activities			
Net income	$ 526.2	$ 456.5	$ 382.4
Reconciliation to cash			
Depreciation and amortization	336.4	317.4	346.9
Amortization of gain	—	(198.4)	(230.7)
Deferred income taxes and investment tax credits, net	430.6	104.9	187.4
Deferred revenue	3.5	100.8	201.7
Contributions to qualified benefit plans	(277.4)	—	(289.3)
Change in - Accounts receivable and accrued revenues	30.1	(50.4)	111.1
Inventories	(2.9)	(1.0)	(34.6)
Other current assets	(20.5)	14.1	24.8
Accounts payable	11.8	21.3	(119.1)
Accrued income taxes, net	(87.4)	(42.7)	43.4
Deferred costs, net	25.9	25.9	46.2
Other current liabilities	44.1	22.0	(11.7)
Other, net	(27.0)	40.0	(29.6)
Cash Provided by Operating Activities	993.4	810.4	628.9
Investing Activities			
Capital expenditures	(830.8)	(798.2)	(814.6)
Investment in transmission affiliate	(6.6)	(5.2)	(25.9)
Proceeds from asset sales	41.5	68.7	16.8
Change in restricted cash	(37.2)	186.2	192.0
Other, net	(59.4)	(85.0)	(104.4)
Cash Used in Investing Activities	(892.5)	(633.5)	(736.1)
Financing Activities			
Exercise of stock options	54.4	90.9	17.0
Purchase of common stock	(193.9)	(156.6)	(29.6)
Dividends paid on common stock	(242.0)	(187.0)	(157.8)
Issuance of long-term debt	720.0	530.0	261.5
Retirement and repurchase of long-term debt	(466.6)	(291.7)	(221.1)
Change in short-term debt	12.0	(167.2)	222.8
Other, net	4.8	9.0	2.9
Cash (Used in) Provided by Financing Activities	(111.3)	(172.6)	95.7
Change in Cash and Cash Equivalents	(10.4)	4.3	(11.5)
Cash and Cash Equivalents at Beginning of Year	24.5	20.2	31.7
Cash and Cash Equivalents at End of Year	$ 14.1	$ 24.5	$ 20.2

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	Accumulated Other Comprehensive Income (Loss)	Stock Options Exercisable	Total
	(Millions of Dollars)					
Balance - December 31, 2008	$ 2.3	$ 751.2	$ 2,584.2	$ (0.9)	$ 0.1	$ 3,336.9
Net income			382.4			382.4
Other comprehensive income						
Hedging, net				0.4		0.4
Comprehensive income	—	—	382.4	0.4	—	382.8
Common stock cash						
dividends of $0.675 per share			(157.8)			(157.8)
Exercise of stock options		17.0				17.0
Purchase of common stock		(29.6)				(29.6)
Tax benefit from share based compensation		6.3				6.3
Stock-based compensation and other		11.4	—		(0.1)	11.3
Balance - December 31, 2009	2.3	756.3	2,808.8	(0.5)	—	3,566.9
Net income			456.5			456.5
Other comprehensive income						
Hedging, net				0.4		0.4
Comprehensive income	—	—	456.5	0.4	—	456.9
Common stock cash						
dividends of $0.80 per share			(187.0)			(187.0)
Exercise of stock options		90.9				90.9
Purchase of common stock		(156.6)				(156.6)
Tax benefit from share based compensation		21.9				21.9
Stock-based compensation and other		9.1				9.1
Balance - December 31, 2010	2.3	721.6	3,078.3	(0.1)	—	3,802.1
Net income			526.2			526.2
Other comprehensive income						
Hedging, net				0.2		0.2
Comprehensive income	—	—	526.2	0.2	—	526.4
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		4.4				4.4
Balance - December 31, 2011	$ 2.3	$ 598.4	$ 3,362.5	$ 0.1	$ —	$ 3,963.3

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

		2011	2010
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$ 3,963.3	$ 3,802.1
Preferred Stock			
Wisconsin Energy			
$.01 par value; authorized 15,000,000 shares; none outstanding		—	—
Wisconsin Electric			
Six Per Cent. Preferred Stock - $100 par value; authorized 45,000 shares; outstanding - 44,498 shares		4.4	4.4
Serial preferred stock -			
$100 par value; authorized 2,286,500 shares; 3.60% Series redeemable at $101 per share; outstanding - 260,000 shares		26.0	26.0
$25 par value; authorized 5,000,000 shares; none outstanding		—	—
Total Preferred Stock		30.4	30.4
Long-Term Debt			
Debentures (unsecured)	4.50% due 2013	300.0	300.0
	6.60% due 2013	45.0	45.0
	6.00% due 2014	300.0	300.0
	5.20% due 2015	125.0	125.0
	6.25% due 2015	250.0	250.0
	4.25% due 2019	250.0	250.0
	2.95% due 2021	300.0	—
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.90% due 2035	90.0	90.0
	5.70% due 2036	300.0	300.0
	6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)	4.81% effective rate due 2030	2.0	2.0
	4.91% due 2011-2030	131.2	135.4
	5.209% due 2011-2030	245.4	251.9
	4.673% due 2011-2031	202.3	—
	6.00% due 2011-2033	145.5	148.7
	6.09% due 2030-2040	275.0	275.0
	5.848% due 2031-2041	215.0	—
Notes (unsecured)	6.50% due 2011	—	450.0
	6.51% due 2013	30.0	30.0
	6.94% due 2028	50.0	50.0
	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 held by Wisconsin Electric	(147.0)	(147.0)
	6.20% due 2033	200.0	200.0
Junior Notes (unsecured)	6.25% due 2067	500.0	500.0
Obligations under capital leases		132.4	141.9
Unamortized discount, net and other		(26.9)	(24.5)
Long-term debt due currently		(32.6)	(473.4)
Total Long-Term Debt		4,614.3	3,932.0
Total Capitalization		$ 8,608.0	$ 7,764.5

(a) Variable interest rate as of December 31, 2011.

The accompanying Notes to Consolidated Financial Statements are an integral part of these 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 operating 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 design, development, construction and 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 and balances within this segment 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: Certain prior period amounts have been reclassified on a basis consistent with the current period financial statement presentation.

On January 20, 2011, our Board of Directors approved a two-for-one stock split of our common stock, which was effected through a stock dividend. New shares were distributed on March 1, 2011 to stockholders of record at the close of business on February 14, 2011. All share and per share information has been restated for all periods presented to reflect this stock split.

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. Beginning in January 2011, 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 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.

For information regarding revenue recognition for We Power, see Note E.

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	2011	2010	2009
	(Millions of Dollars)		
AFUDC - Equity	$ 59.4	$ 32.5	$ 16.0
Gain on Property Sales	2.4	4.4	1.7
Other, net	0.9	3.3	10.8
Total Other Income and Deductions, net	$ 62.7	$ 40.2	$ 28.5

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	2011	2010
	(Millions of Dollars)	
Utility Energy	$ 9,817.7	$ 9,221.1
Non-Utility Energy	3,067.5	2,283.4
Other	92.5	86.3
Total	$ 12,977.7	$ 11,590.8

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 2.8% in 2011 and 2010, and 3.7% in 2009.

PWGS 1, PWGS 2, OC 1 and OC 2 are being depreciated 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 $728.2 million as of December 31, 2011 and $723.9 million as of December 31, 2010.

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

CWIP	2011	2010
	(Millions of Dollars)	
Utility Energy	$ 910.3	$ 806.9
Non-Utility Energy	8.9	761.3
Other	2.1	1.7
Total	$ 921.3	$ 1,569.9

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.

During 2009, Wisconsin Electric accrued AFUDC at a rate of 9.09% as authorized by the PSCW. Consistent with the PSCW's 2008 rate order, Wisconsin Electric accrued AFUDC on 50% of all utility CWIP projects except the Oak Creek AQCS project, which accrued AFUDC on 100% of CWIP. Wisconsin Electric's rates are set to provide a current return on CWIP that does not accrue AFUDC. Based on the 2010 PSCW rate order, effective January 1, 2010 Wisconsin Electric recorded AFUDC on 100% of CWIP associated with the Oak Creek AQCS project, the Edgewater Unit 5 Selective Catalytic Reduction project and the Glacier Hills Wind Park. Wisconsin Electric recorded AFUDC on 50% of all other electric, gas and steam utility CWIP. The AFUDC rate starting January 1, 2010 was 8.83%. This AFUDC accrual policy and rate for Wisconsin Electric continued through 2011 and will continue through 2012.

Wisconsin Electric is also accruing AFUDC on 100% of the biomass project.

During 2009, Wisconsin Gas accrued AFUDC at a rate of 10.80% on 50% of its CWIP as authorized by the PSCW in its 2008 rate order. Wisconsin Gas' rates are set to provide a current return on CWIP that does not accrue AFUDC. Based on the 2010 PSCW rate order, effective January 1, 2010 Wisconsin Gas recorded AFUDC on 50% of all CWIP using an AFUDC rate of 9.05%. This AFUDC accrual policy and rate for Wisconsin Gas continued through 2011 and will continue through 2012.

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

	2011	2010	2009
	(Millions of Dollars)		
AFUDC - Debt	$ 24.7	$ 13.5	$ 6.7
AFUDC - Equity	$ 59.4	$ 32.5	$ 16.0

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. For further information on the accounting for capitalized interest and deferred carrying costs associated with the construction of our PTF power plants, see Note E.

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. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. Shares that are anti-dilutive are excluded from the calculation. All stock options outstanding during 2011 were included in the computation of diluted earnings per share. For 2010 and 2009, the calculation of diluted earnings per share excluded an immaterial number of out-of-the money stock options that had an anti-dilutive effect.

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

Materials, Supplies and Inventories	2011	2010
	(Millions of Dollars)	
Fossil Fuel	$ 169.2	$ 182.4
Materials and Supplies	114.1	105.2
Natural Gas in Storage	98.7	91.5
Total	$ 382.0	$ 379.1

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. We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet. 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 F.

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.

Restricted Cash: For 2011, restricted cash consists of the settlement we received from the DOE during the first quarter of 2011, which is being returned, net of costs incurred, to customers. For 2010, restricted cash consisted of cash proceeds that we received from the sale of Point Beach that were used for the benefit of our customers. As of December 31, 2011, all restricted cash is classified as current.

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, 2011 and 2010, 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 2011 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, 2011, 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, 2011 and 2010. 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 Q.

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 H.

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 I.

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

	2011	2010	2009
Risk-free interest rate	0.2% - 3.4%	0.2% - 3.9%	0.3% - 2.5%
Dividend yield	3.9%	3.7%	3.0%
Expected volatility	19.0%	20.3%	25.9%
Expected life (years)	5.5	5.9	6.2
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$ 3.17	$ 3.36	$ 4.01

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Presentation of Comprehensive Income: In June 2011, the Financial Accounting Standards Board (FASB) issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of changes in stockholders' equity. The guidance gives entities the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued an amendment to indefinitely defer one of the requirements contained in its June 2011 final standard. That requirement called for reclassification adjustments from accumulated other comprehensive income to be measured and presented by income statement line item in net income and also in other comprehensive income. This guidance, including the related deferral, is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied retrospectively. We are currently assessing the effects this guidance may have on our consolidated financial statements.

Fair Value Measurement: In May 2011, the FASB issued guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. Under the new guidance, required disclosures are expanded, particularly for fair value measurements that are categorized within Level 3 of the fair value hierarchy, for which quantitative information about the unobservable inputs, the valuation processes used by the entity, and the sensitivity of the measurement to the unobservable inputs will be required. Entities will also be required to disclose the categorization, by level of the fair value hierarchy, of items that are not measured at fair value in the balance sheets but for which the fair value is required to be disclosed. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied prospectively. We are currently assessing the effects this guidance may have on our consolidated financial statements.

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, 2011 and 2010, we had approximately $11.0 million and $16.5 million, respectively, of net regulatory assets that were not earning a return. These regulatory assets are expected to be recovered from customers over a period of one to five years.

In December 2009, the PSCW issued a rate order effective January 1, 2010 that, among other things, reaffirmed our accounting for the regulatory assets and liabilities identified below. The rate order provided for the recovery over an eight year period of specific regulatory assets, the largest of which is the balance of the remaining deferred transmission costs. The order also specified that the deferred Point Beach gain would be passed on to customers as authorized in the prior rate case such that the final credits were issued by the end of 2010.

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

	2011	2010
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$ 647.8	$ 542.6
Deferred income tax related	121.2	89.9
Escrowed electric transmission costs	118.3	138.0
Deferred unrecognized OPEB costs	102.9	85.7
Deferred plant related -- capital lease	73.2	77.1
Deferred environmental costs	48.5	56.7
Other, net	153.8	154.5
Total regulatory assets	$ 1,265.7	$ 1,144.5
Regulatory Liabilities		
Deferred cost of removal obligations	$ 728.2	$ 723.9
Escrowed bad debt costs	69.0	18.5
Other, net	118.7	156.7
Total regulatory liabilities	$ 915.9	$ 899.1

Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet.

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

Edison Sault: Effective May 4, 2010, we sold Edison Sault to Cloverland Electric Cooperative for approximately $63.0 million. We reclassified the operations related to Edison Sault as discontinued operations in the accompanying Consolidated Income Statements. Discontinued Edison Sault operations had no significant impact on our Consolidated Statements of Cash Flows for the years ended December 31, 2010 and 2009. We retained Edison Sault's ownership interest in ATC.

Water Utility Operations: Effective April 30, 2009, we sold our water utility to the City of Mequon, Wisconsin for approximately $14.5 million. We reclassified the water utility income as discontinued operations in the accompanying Consolidated Income Statements. Discontinued water operations had no material impact on the Consolidated Statement of Cash Flows for the year ended December 31, 2009.

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

	2011	2010	2009
	(Millions of Dollars)		
Income from Continuing Operations	$ 512.8	$ 454.4	$ 375.7
Income from Discontinued Edison Sault operations, net of tax	—	0.7	1.5
Income from Discontinued Water operations, net of tax	—	—	0.3
Income from Discontinued other operations, net of tax (a)	13.4	1.4	4.9
Net Income	$ 526.2	$ 456.5	$ 382.4

(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, a subsidiary of Alliant Energy Corp. (WPL), for our net book value, including working capital, of approximately $38 million. This transaction was treated as a sale of an asset.

E -- ACCOUNTING AND REPORTING FOR POWER THE FUTURE GENERATING UNITS

Background: As part of our PTF strategy, our non-utility subsidiary, We Power, built four new generating units, PWGS 1, PWGS 2, OC 1 and OC 2, which are leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW. The leases are designed to recover the capital costs of the plant, including a return. PWGS 1, PWGS 2, OC 1 and OC 2 were placed in service in July 2005, May 2008, February 2010 and January 2011, respectively. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

The Oak Creek expansion includes common projects that benefit the existing units at this site as well as the new units. These projects include a coal handling facility and a water intake system, which were placed in service in November 2007 and January 2009, respectively.

During Construction: Under the terms of each lease, we collected in then current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for our PTF units. Our pre-tax cost of capital was approximately 14%. The carrying costs that we collected in rates were recorded as deferred revenue and are amortized to revenue over the term of each lease. During the construction of our PTF units, we capitalized interest costs at an overall weighted-average pre-tax cost of interest, which was approximately 5% for the year ended December 31, 2010. Capitalized interest is included in the total cost of the PTF units.

Plant in Service: Now that the PTF units are in service, we expect to continue to recover in rates the lease costs which reflect the authorized cash construction costs of the units plus a return on the investment. The authorized cash costs were established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs were recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first five years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return under each lease was established at rates determined in accordance with the terms of each lease.

We recognize 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. We depreciate the PTF assets over their estimated useful life.

F -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2011 and 2010:

	2011	2010
	(Millions of Dollars)	
Balance as of January 1	$ 52.6	$ 57.9
Liabilities Incurred	0.6	—
Liabilities Settled	(2.2)	(2.5)
Accretion	3.0	3.1
Cash Flow Revisions	1.5	(5.9)
Balance as of December 31	$ 55.5	$ 52.6

G -- 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 two tolling and purchased power agreements with third parties which represent variable interests. We account for one of these agreements, with an independent power producer, as an operating lease. The agreement has a remaining term of approximately one and a half years. We have examined the risks of the entity including the impact of operations and maintenance, dispatch, financing, fuel costs, remaining useful life and other factors, and have determined that we are not the primary beneficiary of this entity. We have concluded that we do not have the power to direct the activities that would most significantly affect the economic performance of the entity over its remaining life.

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the remaining term of 11 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 $309.5 million of required payments over the remaining term of these agreements. We believe that the required lease payments under these contracts will continue to be recoverable in rates. Total capacity and lease payments under these contracts in 2011, 2010 and 2009 were $65.9 million, $64.2 million and $62.2 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

H -- INCOME TAXES

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

Income Taxes	2011	2010	2009
		(Millions of Dollars)	
Current tax expense (benefit)	$ (166.7)	$ 144.9	$ 28.1
Deferred income taxes, net	434.8	108.6	191.2
Investment tax credit, net	(4.2)	(3.6)	(3.8)
Total Income Tax Expense	$ 263.9	$ 249.9	$ 215.5

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:

Income Tax Expense	2011 Amount	2011 Effective Tax Rate	2010 Amount	2010 Effective Tax Rate	2009 Amount	2009 Effective Tax Rate
	(Millions of Dollars)					
Expected tax at statutory federal tax rates	$ 271.8	35.0 %	$ 246.5	35.0 %	$ 206.9	35.0 %
State income taxes net of federal tax benefit	40.1	5.2 %	35.8	5.1 %	31.8	5.4 %
AFUDC - Equity	(20.8)	(2.7)%	(11.4)	(1.6)%	(5.6)	(0.9)%
Domestic production activities deduction	(12.6)	(1.6)%	(12.6)	(1.8)%	(8.3)	(1.4)%
Production tax credits - wind	(8.7)	(1.1)%	(7.2)	(1.0)%	(7.1)	(1.2)%
Investment tax credit restored	(4.2)	(0.5)%	(3.6)	(0.5)%	(3.8)	(0.6)%
Other, net	(1.7)	(0.3)%	2.4	0.3 %	1.6	0.2 %
Total Income Tax Expense	$ 263.9	34.0 %	$ 249.9	35.5 %	$ 215.5	36.5 %

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	2011	2010
	(Millions of Dollars)	
Current		
Employee benefits and compensation	$ 14.6	$ 14.3
Other	57.1	33.5
Total Current Deferred Tax Assets	71.7	47.8
Non-current		
Future federal tax benefits	328.5	—
Deferred revenues	279.7	305.9
Employee benefits and compensation	103.6	110.2
Property-related	28.3	30.3
Construction advances	25.4	118.3
Emission allowances	1.0	2.6
Other	34.0	30.8
Total Non-Current Deferred Tax Assets	800.5	598.1
Total Deferred Tax Assets	$ 872.2	$ 645.9

Deferred Tax Liabilities	2011	2010
	(Millions of Dollars)	
Current		
Prepaid items	$ 50.1	$ 46.9
Total Current Deferred Tax Liabilities	50.1	46.9
Non-current		
Property-related	2,020.7	1,346.8
Employee benefits and compensation	232.8	179.5
Investment in transmission affiliate	129.2	112.4
Deferred transmission costs	47.4	53.1
Other	66.5	61.1
Total Non-current Deferred Tax Liabilities	2,496.6	1,752.9
Total Deferred Tax Liabilities	$ 2,546.7	$ 1,799.8

Consolidated Balance Sheet Presentation	2011	2010
Current Deferred Tax Asset	$ 21.6	$ 0.9
Non-Current Deferred Tax Liability	$ 1,696.1	$ 1,154.8

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, 2011, we had approximately $867.1 million and $25.0 million of net operating loss and tax credit carryforwards, respectively. The net operating loss and tax credit carryforwards resulted in deferred tax assets of $303.5 million and $25.0 million, respectively, as of December 31, 2011. The tax credit and net operating loss carryforwards begin to expire in 2029 and 2030, respectively. We anticipate that we will have future taxable income sufficient to utilize these deferred tax assets.

On January 1, 2007, we adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2011	2010
	(Millions of Dollars)	
Balance as of January 1	$ 29.5	$ 35.4
Additions based on tax positions related to the current year	—	0.8
Additions for tax positions of prior years	—	10.4
Reductions for tax positions of prior years	(13.9)	(2.5)
Reductions due to statute of limitations	(2.5)	(0.3)
Settlements during the period	(2.0)	(14.3)
Balance as of December 31	$ 11.1	$ 29.5

The amount of unrecognized tax benefits as of December 31, 2011 and 2010 excludes deferred tax assets related to uncertainty in income taxes of $11.0 million and $16.9 million, respectively. As of December 31, 2011 and 2010, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately $0.1 million and $2.3 million, respectively.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2011, 2010 and 2009, we recognized approximately $0.7 million, $4.1 million and $2.0 million, respectively, of accrued interest in the Consolidated Income Statements. For the year ended December 31, 2011, we recognized a benefit of $0.3 million in the Consolidated Income Statements related to a reduction of accrued penalties. For the years ended December 31, 2010 and 2009, we recognized no penalties in the Consolidated Income Statements. We had approximately $2.0 million and $8.2 million of interest accrued and zero and approximately $0.3 million of penalties accrued on the Consolidated Balance Sheets as of December 31, 2011 and 2010, 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 Federal and the state of Wisconsin. Currently, the tax years of 2007 through 2011 are subject to Federal and Wisconsin examination.

I -- COMMON EQUITY

As of December 31, 2011 and 2010, we had 325,000,000 shares of common stock authorized under our charter, of which 230,486,804 and 233,771,194 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 other than necessary adjustments as a result of our stock split.

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:

	2011	2010	2009
	(Millions of Dollars)		
Performance units	$ 24.1	$ 26.0	$ 14.0
Stock options	2.6	7.6	10.8
Restricted stock	1.8	1.5	1.0
Share-based compensation expense	$ 28.5	$ 35.1	$ 25.8
Related Tax Benefit	$ 11.4	$ 14.1	$ 10.3

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 and vest on a cliff-basis after a three year period. Options expire no later than ten 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, 2011 will be exercised.

The following is a summary of our stock option activity during 2011:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2011	13,036,466	$ 20.81		
Granted	458,180	$ 29.35		
Exercised	(2,855,896)	$ 19.07		
Forfeited	—	$ —		
Outstanding as of December 31, 2011	10,638,750	$ 21.65	5.4	$ 141.6
Exercisable as of December 31, 2011	7,534,980	$ 21.14	4.5	$ 104.1

In January 2012, the Compensation Committee awarded 938,770 non-qualified stock options with an exercise price of $34.88 to our officers and key executives under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $36.1 million, $62.1 million and $12.0 million, respectively. Cash received from options exercised during the years ended December 31, 2011, 2010 and 2009 was $54.4 million, $90.9 million and $17.0 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $14.3 million, $24.1 million and $4.8 million, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2011:

	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)
$11.52 to $17.10	1,972,594	$ 16.07	2.3	1,972,594	$ 16.07	2.3
$19.74 to $21.11	3,586,456	$ 20.62	5.9	1,420,186	$ 19.88	4.3
$23.88 to $29.35	5,079,700	$ 24.54	6.2	4,142,200	$ 23.99	5.6
	10,638,750	$ 21.65	5.4	7,534,980	$ 21.14	4.5

The following table summarizes information about our non-vested options during 2011:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-Vested as of January 1, 2011	5,272,570	$ 4.27
Granted	458,180	$ 3.17
Vested	(2,626,980)	$ 4.64
Forfeited	—	$ —
Non-Vested as of December 31, 2011	3,103,770	$ 3.78

As of December 31, 2011, total compensation costs related to non-vested stock options not yet recognized was approximately $0.6 million, which is expected to be recognized over the next 19 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 2011:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2011	205,404	
Granted	74,850	$ 29.00
Released	(83,452)	$ 18.82
Forfeited	(4,244)	$ 26.62
Outstanding as of December 31, 2011	192,558	

Recipients of previously issued restricted shares have the right to vote the shares and receive dividends, and the shares have vesting periods ranging up to 10 years.

In January 2012, the Compensation Committee awarded 94,959 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 $2.5 million, $2.3 million and $0.9 million for the years ended December 31, 2011, 2010, and 2009, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was $0.8 million, $0.7 million and $0.3 million, respectively.

As of December 31, 2011, total compensation cost related to restricted stock not yet recognized was approximately $2.4 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Performance Units: In January 2011, 2010 and 2009, the Compensation Committee awarded 435,690, 555,830 and 666,440 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, 2011, 2010 and 2009 vested and were settled during the first quarter of 2012, 2011 and 2010 and had a total intrinsic value of $26.7 million, $12.6 million and $9.8 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately $9.7 million, $4.3 million and $3.4 million, respectively.

In January 2012, the Compensation Committee awarded 346,570 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

As of December 31, 2011, total compensation cost related to performance units not yet recognized was approximately $18.3 million, which is expected to be recognized over the next 19 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.

The January 2010 PSCW rate case order requires Wisconsin Electric and Wisconsin Gas to maintain capital structures that differ from GAAP as they reflect regulatory adjustments. Wisconsin Electric is required to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas is required to maintain a capital structure which has a common equity range of between 45.0% and 50.0%. 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, 2011, 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 $3.5 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2011.

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.

Common Stock Activity: 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 2011, 2010 or 2009.

During 2011, 2010 and 2009, our plan agents purchased 3.0 million shares at a cost of $93.9 million, 5.8 million shares at a cost of $156.6 million and 1.4 million shares at a cost of $29.6 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2011, 2010 and 2009, we received proceeds of $54.4 million, $90.9 million and $17.0 million, respectively, related to the exercise of stock options.

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. 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. Through December 31, 2011, we repurchased approximately 3.2 million shares pursuant to this program at an average cost of $30.79 per share and a total cost of $100.0 million.

J -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2011, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2012	$ 20.3
2013	396.3
2014	322.4
2015	399.5
2016	27.4
Thereafter	3,375.5
Total	$ 4,541.4

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

In September 2011, Wisconsin Electric issued $300 million of 2.95% Debentures due September 15, 2021. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other general corporate purposes.

On April 1, 2011, we used cash and short-term borrowings to retire $450 million of long-term debt that matured.

In January 2011, we issued a total of $420 million in long-term debt ($205 million aggregate principal amount of 4.673% Series B Senior Notes due January 19, 2031 and $215 million aggregate principal amount of 5.848% Series B Senior Notes due January 19, 2041) and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. The Series B Senior Notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 2.

In February 2010, we issued a total of $530 million in long-term debt ($255 million aggregate principal amount of 5.209% Series A Senior Notes due February 11, 2030 and $275 million aggregate principal amount of 6.09% Series A Senior Notes due February 11, 2040) and used the net proceeds to repay debt incurred to finance the construction of OC 1. The Series A Senior Notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 1.

During 2010, we retired $281.5 million of unsecured notes through the issuance of long-term and short-term debt.

During 2009, we issued $261.5 million of long-term debt, including $250 million of debentures under an existing shelf registration statement filed by Wisconsin Electric with the SEC in August 2007. The net proceeds were used to repay short-term debt and for other general corporate purposes.

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, 2011 and 2010, the repurchased bonds were still outstanding, but were reported as a reduction 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 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 $31.3 million and $30.2 million in lease payments during 2011 and 2010, 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 $132.4 million as of December 31, 2011, 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	2011	2010
	(Millions of Dollars)	
Leased Facilities		
Long-term power purchase commitment	$ 140.3	$ 140.3
Accumulated amortization	(81.1)	(75.5)
Total Leased Facilities	$ 59.2	$ 64.8

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2011 are as follows:

	(Millions of Dollars)
2012	$ 38.9
2013	40.4
2014	41.9
2015	43.5
2016	45.1
Thereafter	85.4
Total Minimum Lease Payments	295.2
Less: Estimated Executory Costs	(74.9)
Net Minimum Lease Payments	220.3
Less: Interest	(87.9)
Present Value of Net Minimum Lease Payments	132.4
Less: Due Currently	(12.4)
	$ 120.0

K -- SHORT-TERM DEBT

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

Short-Term Debt	2011 Balance	2011 Interest Rate	2010 Balance	2010 Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$ 669.9	0.27 %	$ 657.9	0.30 %

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

	2011	2010
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$ 717.3	$ 821.0
Average Short-Term Debt Outstanding	$ 505.1	$ 528.7
Weighted-Average Interest Rate	0.25 %	0.32 %

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, 2011, we had approximately $1.2 billion of available undrawn lines under our bank back-up credit facilities and approximately $669.9 million of commercial paper outstanding that was supported by the available lines of credit. Our bank back-up credit facilities expire in December 2013.

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, 2011, 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. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of December 31, 2011, we recognized $29.6 million in regulatory assets and $21.7 million in regulatory liabilities related to derivatives in comparison to $22.0 million in regulatory assets and $15.3 million in regulatory liabilities as of December 31, 2010.

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 $2.5 million is recorded in other deferred charges and other assets, and the long-term portion of our derivative liabilities of $0.7 million is recorded in other long-term liabilities. Our Consolidated Balance Sheets as of December 31, 2011 and 2010 include:

	December 31, 2011		December 31, 2010	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$ 2.1	$ 9.1	$ 2.5	$ 11.6
Fuel Oil	0.3	0.1	4.4	—
FTRs	5.7	—	5.9	—
Coal	12.5	—	2.9	—
Total	$ 20.6	$ 9.2	$ 15.7	$ 11.6

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:

	2011		2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	71.8 million Dth	$ (33.4)	83.2 million Dth	$ (43.8)
Power	zero MWh	—	234,720 MWh	(0.5)
Fuel Oil	13.0 million gallons	6.9	8.1 million gallons	(0.5)
FTRs	23,718 MW	12.5	25,234 MW	19.2
Total		$ (14.0)		$ (25.6)

As of December 31, 2011 and 2010, we posted collateral of $11.9 million and $11.7 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

For the year ended December 31, 2011, we reclassified $0.2 million and for the years ended December 31, 2010 and 2009, we reclassified $0.4 million in treasury lock agreement settlement payments deferred in Accumulated Other Comprehensive Income, as an increase to Interest Expense. We estimate that during the next 12 months, $0.1 million will be reclassified from Accumulated Other Comprehensive Income as a reduction in earnings.

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 -- Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an on-going 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, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 45.5	$ —	$ —	$ 45.5
Derivatives	0.3	14.6	5.7	20.6
Total	$ 45.8	$ 14.6	$ 5.7	$ 66.1
Liabilities:				
Derivatives	$ 8.2	$ 1.0	$ —	$ 9.2
Total	$ 8.2	$ 1.0	$ —	$ 9.2

Recurring Fair Value Measures	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 8.3	$ —	$ —	$ 8.3
Derivatives	4.5	5.3	5.9	15.7
Total	$ 12.8	$ 5.3	$ 5.9	$ 24.0
Liabilities:				
Derivatives	$ 6.1	$ 5.5	$ —	$ 11.6
Total	$ 6.1	$ 5.5	$ —	$ 11.6

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents (i) for 2010, the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of Point Beach, and (ii) for 2011, the settlement we received from the DOE during the first quarter of 2011, which is being 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:

	2011	2010
	(Millions of Dollars)	
Balance as of January 1	$ 5.9	$ 5.8
Realized and unrealized gains (losses)	—	—
Purchases and issuances	16.1	17.9
Settlements	(16.3)	(17.8)
Transfers in and/or out of Level 3	—	—
Balance as of December 31	$ 5.7	$ 5.9
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:

	2011		2010	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$ 30.4	$ 25.1	$ 30.4	$ 23.5
Long-term debt including current portion	$ 4,541.4	$ 5,179.9	$ 4,288.0	$ 4,578.0

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. The plans provide defined 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 2011	Pension 2010	OPEB 2011	OPEB 2010
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$ 1,222.8	$ 1,160.7	$ 368.3	$ 374.7
Service cost	15.9	23.7	10.4	11.2
Interest cost	67.6	68.4	20.8	21.2
Participants' contributions	—	—	11.6	6.5
Plan amendments	—	—	0.4	0.3
Actuarial loss (gain)	98.0	53.4	7.6	(23.8)
Curtailments	—	—	—	(1.0)
Gross benefits paid	(73.7)	(83.4)	(30.3)	(21.8)
Federal subsidy on benefits paid	N/A	N/A	0.9	1.0
Benefit Obligation at December 31	$ 1,330.6	$ 1,222.8	$ 389.7	$ 368.3
Change in Plan Assets				
Fair Value at January 1	$ 1,059.5	$ 1,026.0	$ 216.7	$ 202.6
Actual earnings on plan assets	33.8	110.1	9.0	24.5
Employer contributions	242.9	6.8	48.4	4.9
Participants' contributions	—	—	11.6	6.5
Gross benefits paid	(73.7)	(83.4)	(30.3)	(21.8)
Fair Value at December 31	$ 1,262.5	$ 1,059.5	$ 255.4	$ 216.7
Net Liability	$ 68.1	$ 163.3	$ 134.3	$ 151.6

As of December 31, 2011, our qualified pension plans were over-funded by $24.4 million and our non-qualified pension plans were under-funded by $92.5 million. As of December 31, 2010, our qualified and non-qualified pension plans were under-funded by $71.7 million and $91.6 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 2011	Pension 2010	OPEB 2011	OPEB 2010
	(Millions of Dollars)			
Other deferred charges	$ —	$ —	$ 20.3	$ 38.3
Other long-term liabilities	68.1	163.3	154.6	189.9
Net liability	$ 68.1	$ 163.3	$ 134.3	$ 151.6

The accumulated benefit obligation for all defined benefit plans was $1,329.4 million and $1,222.5 million as of December 31, 2011 and 2010, 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 2011	Pension 2010	OPEB 2011	OPEB 2010
	(Millions of Dollars)			
Net actuarial loss	$ 633.4	$ 521.0	$ 108.1	$ 98.9
Prior service costs (credits)	14.4	16.7	(6.1)	(8.5)
Transition obligation	—	—	0.3	0.6
Total	$ 647.8	$ 537.7	$ 102.3	$ 91.0

We estimate that 2012 periodic pension and OPEB costs will include the amortization of previously unrecognized benefit costs referred to above of $43.9 million and $5.5 million, respectively.

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

	Pension			OPEB		
	2011	2010	2009	2011	2010	2009
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$ 15.9	$ 23.7	$ 23.3	$ 10.4	$ 11.2	$ 8.7
Interest cost	67.6	68.4	72.3	20.8	21.2	20.5
Expected return on plan assets	(82.1)	(78.2)	(95.4)	(16.9)	(14.3)	(13.6)
Amortization of:						
Transition obligation	—	—	—	0.3	0.3	0.3
Prior service cost (credit)	2.2	2.2	2.2	(1.9)	(11.9)	(12.6)
Actuarial loss	34.0	26.8	18.9	6.2	10.8	8.9
Curtailment (gain)	—	—	—	—	(0.4)	—
Net Periodic Benefit Cost	$ 37.6	$ 42.9	$ 21.3	$ 18.9	$ 16.9	$ 12.2

In addition to the costs above, in 2011 we recorded net pension costs of less than $0.04 per share related to the settlement of pension litigation. See Note R -- Commitments and Contingencies in this report. The charges were after considering insurance and reserves established in the prior year.

	Pension			OPEB		
	2011	2010	2009	2011	2010	2009
Weighted-Average assumptions used to determine benefit obligations as of Dec. 31						
Discount rate	5.05%	5.60%	6.05%	5.20%	5.70%	5.75%
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	5.60%	6.05%	6.50%	5.70%	5.75%	6.50%
Expected return on plan assets	7.25%	7.25%	8.25%	7.50%	7.50%	8.25%
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	2011	2010	2009
Health care cost trend rate assumed for next year (Pre 65 / Post 65)	8.0%/12%	7.5%/16%	7.5%/20%
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)	2017/2017	2015/2016	2015/2016

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.50%, respectively, in 2011 and 2010. The expected long-term rate of return for all plan assets was 8.25% in 2009. 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	$ 31.9	$ (26.8)
Total of service and interest cost components	$ 3.8	$ (3.1)

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, 2011			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 8.5	$ —	$ —	$ 8.5
Equities:				
U.S. Equity	455.1	—	—	455.1
International Equity	100.4	33.9	—	134.3
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	76.9	502.8	—	579.7
International Bonds	40.9	44.0	—	84.9
Total	$ 681.8	$ 580.7	$ —	$ 1,262.5

	As of December 31, 2010			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 21.1	$ —	$ —	$ 21.1
Equities:				
U.S. Equity	217.2	247.5	—	464.7
International Equity	81.1	21.6	—	102.7
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	49.7	361.5	—	411.2
International Bonds	31.8	28.0	—	59.8
Total	$ 400.9	$ 658.6	$ —	$ 1,059.5

(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, 2011 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 2.4	$ —	$ —	$ 2.4
Equities:				
U.S. Equity	113.6	—	—	113.6
International Equity	32.1	2.3	—	34.4
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	8.2	83.0	—	91.2
International Bonds	8.7	5.1	—	13.8
Total	$ 165.0	$ 90.4	$ —	$ 255.4

Asset Category - OPEB	As of December 31, 2010 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 1.5	$ —	$ —	$ 1.5
Equities:				
U.S. Equity	41.6	80.1	—	121.7
International Equity	5.2	1.4	—	6.6
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	21.8	59.4	—	81.2
International Bonds	2.0	3.7	—	5.7
Total	$ 72.1	$ 144.6	$ —	$ 216.7

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

Cash Flows:

Employer Contributions	Pension Qualified	Pension Non-Qualified	OPEB
		(Millions of Dollars)	
2009	$ 270.0	$ 5.8	$ 24.3
2010	$ —	$ 6.8	$ 4.9
2011	$ 236.4	$ 6.5	$ 48.4

The following table identifies our expected benefit payments over the next 10 years:

Year	Pension	Gross OPEB	Expected Medicare Part D Subsidy
		(Millions of Dollars)	
2012	$ 110.1	$ 20.2	$ (0.9)
2013	$ 101.3	$ 20.8	$ —
2014	$ 104.4	$ 22.2	$ —
2015	$ 103.6	$ 23.5	$ —
2016	$ 103.9	$ 24.7	$ —
2017-2021	$ 535.2	$ 136.4	$ —

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 $14.1 million, $13.8 million and $14.1 million during 2011, 2010 and 2009, respectively.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $15.3 million as of December 31, 2011.

O -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of December 31, 2011, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding	Liability Recorded
		(Millions of Dollars)	
Guarantees	$ 2.7	$ 0.1	$ —
Letters of Credit	$ 1.6	$ 0.1	$ —

We provide guarantees to support obligations of our affiliates to third parties under agreements and surety bonds. In the event our affiliates fail to perform, we would be responsible for the obligations.

Wisconsin Electric is subject to the potential retrospective premiums that could be assessed under its insurance program.

P -- SEGMENT REPORTING

Our operating segments as of December 31, 2011 include a utility energy segment and a non-utility energy segment. We have organized our operating 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 operating segments for each of the three years ended December 31, 2011 is shown in the following table. The segment information below includes income from discontinued operations as a result of the sale of Edison Sault in May 2010 and the water utility in April 2009.

Year Ended	Operating Segments — Energy — Utility	Operating Segments — Energy — Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
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
December 31, 2010					
Operating Revenues (b)	$ 4,165.3	$ 320.2	$ 0.5	$ (283.5)	$ 4,202.5
Depreciation and Amortization	$ 251.4	$ 53.5	$ 0.7	$ —	$ 305.6
Operating Income (Loss)	$ 564.0	$ 252.4	$ (6.0)	$ —	$ 810.4
Equity in Earnings of Unconsolidated Affiliates	$ 60.1	$ —	$ (0.2)	$ —	$ 59.9
Interest Expense, Net	$ 117.2	$ 40.3	$ 52.8	$ (3.9)	$ 206.4
Income Tax Expense (Benefit)	$ 192.1	$ 84.9	$ (27.1)	$ —	$ 249.9
Income from Discontinued Operations, Net of Tax	$ 0.7	$ —	$ 1.4	$ —	$ 2.1
Net Income (Loss)	$ 354.2	$ 128.4	$ 456.4	$ (482.5)	$ 456.5
Capital Expenditures	$ 687.0	$ 109.3	$ 1.9	$ —	$ 798.2
Total Assets (c)	$ 11,997.4	$ 2,914.2	$ 5,075.9	$ (6,927.7)	$ 13,059.8
December 31, 2009					
Operating Revenues (b)	$ 4,092.0	$ 163.1	$ 0.2	$ (154.4)	$ 4,100.9
Depreciation and Amortization	$ 313.1	$ 29.2	$ 0.7	$ —	$ 343.0
Operating Income (Loss)	$ 550.9	$ 120.1	$ (10.7)	$ —	$ 660.3
Equity in Earnings of Unconsolidated Affiliates	$ 59.1	$ —	$ (0.2)	$ —	$ 58.9
Interest Expense, Net	$ 117.5	$ 14.7	$ 54.3	$ (29.8)	$ 156.7
Income Tax Expense (Benefit)	$ 186.7	$ 43.4	$ (14.6)	$ —	$ 215.5
Income from Discontinued Operations, Net of Tax	$ 1.8	$ —	$ 4.9	$ —	$ 6.7
Net Income (Loss)	$ 334.2	$ 63.8	$ 382.3	$ (397.9)	$ 382.4
Capital Expenditures	$ 547.0	$ 253.2	$ 14.4	$ —	$ 814.6
Total Assets (c)	$ 10,784.6	$ 2,754.1	$ 5,385.5	$ (6,226.3)	$ 12,697.9

(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 $2,369.0 million, $1,785.9 million and $889.1 million is included in Total Assets as of December 31, 2011, 2010 and 2009, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

Q -- 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, 2011, 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 are 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 new generating units constructed as part of our PTF strategy. ATC reimburses us for these costs when new generation is placed in service. As of December 31, 2011 and 2010, we had a receivable of $5.4 million and $3.8 million, respectively, for these items. During the years ended December 31, 2011, 2010 and 2009, our equity in earnings from ATC was $62.5 million, $60.1 million and $59.1 million, respectively. During the years ended December 31, 2011, 2010 and 2009, distributions received from ATC were $49.7 million, $49.3 million and $46.6 million, respectively.

We provided and received services from the following associated companies during 2011, 2010 and 2009:

Equity Investee	2011	2010	2009
		(Millions of Dollars)	
Services Provided			
–ATC	$ 10.8	$ 16.9	$ 22.3
Services Received			
–ATC	$ 219.2	$ 220.8	$ 196.0

As of December 31, 2011 and 2010, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2011	2010
	(Millions of Dollars)	
Services Provided		
–ATC	$ 0.7	$ 0.9
Services Received		
–ATC	$ 18.1	$ 18.5

R -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2012 capital expenditures. During 2012, we estimate that total capital expenditures will be approximately $740.2 million.

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)
2012	$ 16.3
2013	6.5
2014	3.9
2015	4.0
2016	3.7
Thereafter	29.0
Total	$ 63.4

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. We have established reserves as deemed appropriate for these indemnification provisions.

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 $21 million to $65 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, 2011, we have established reserves of $37.5 million 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 2011, 2010 and 2009, Wisconsin Electric incurred $0.2 million, $0.4 million and $0.3 million respectively, in landfill remediation expenses. As of December 31, 2011, we have no reserves established related to coal combustion product landfill sites.

EPA - Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the 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 scheduled to begin service in 2012. The reductions are expected to be achieved by 2013 through a combination of installing new pollution control equipment, upgrading existing equipment and retiring certain older units. Through December 31, 2011, we have spent approximately $1.0 billion associated with the installation of air quality controls and have retired four coal units as part of our plan under the Consent Decree. The total cost of implementing this agreement is currently estimated to be approximately $1.1 billion over the ten year period ending 2013.

Valley Power Plant Title V Air Permit: The WDNR issued a renewed Title V operating permit for VAPP on February 28, 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested a contested case hearing on certain conditions of the permit, and that request was granted. The Sierra Club also filed a petition requesting that the EPA remand the permit to the WDNR to require lower emission limits for particulate matter, SO_2 and NO_x, and to revise certain record-keeping requirements. No timeline has been set by the EPA to respond to that petition. We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards.

The Company filed an application with the PSCW on December 9, 2011 for authority to replace and upgrade the Lincoln Arthur natural gas main, which would also have the capability to accommodate the increased natural gas required if VAPP were to convert from coal to natural gas in the future. We also submitted a letter to the EPA on December 8, 2011 with four voluntary goals, which included: (1) reduce annual SO_2 emissions from the plant to no more than 4,500 tons (a 65% decrease from 2001 emission levels); (2) install a dry sorbent injection system at VAPP that is needed to meet the utility MACT rules earlier than the rules require if the installation would provide a direct economic benefit to customers and is approved by the PSCW; (3) hold an open house and tour of VAPP in 2012 to help inform the community on the plant, the unique role that it plays in the community, and to share environmental successes and future plans; and (4) convert VAPP to natural gas fuel by the 2017/2018 timeframe, provided we can demonstrate a direct economic benefit to customers and obtain authorization from the PSCW.

Oak Creek Construction Contract: Bechtel, the contractor of the Oak Creek expansion under a fixed price contract, submitted claims to us on December 22, 2008 for cost and schedule relief related to the delay of the in-service dates for OC 1 and OC 2. These claims were asserted against Elm Road Services, LLC (ERS), the project manager for the construction of the Oak Creek expansion and agent for the joint owners of OC 1 and OC 2. On October 30, 2009, Bechtel amended its claim to increase its request for cost relief and schedule relief. In its amended claim, Bechtel requested cost relief totaling approximately $517.5 million and schedule relief that would have resulted in approximately seven months of relief from liquidated damages beyond the guaranteed in-service date of September 29, 2009 for OC 1 and approximately four months of relief from liquidated damages beyond the guaranteed in-service date of September 29, 2010 for OC 2.

Bechtel's first claim was based on the alleged impact of severe weather and certain labor-related matters. Pursuant to its amended claim, Bechtel was requesting approximately $445.5 million in costs related to changed weather and labor conditions. Bechtel's second claim of approximately $72 million sought cost and schedule relief for the alleged effects of ERS-directed changes and delays allegedly caused by ERS prior to the issuance of the Full Notice to Proceed in July 2005. These claims, as well as claims submitted by ERS related to the rights of the parties under the construction contract and ERS counterclaims, had been submitted to binding arbitration.

Effective December 16, 2009, ERS and Bechtel entered into the Settlement Agreement that settled the claims between them regarding OC 1 and OC 2. Pursuant to the terms of this Settlement Agreement, ERS will pay to Bechtel $72 million to settle these claims payable upon the achievement of specific project milestones. As of December 31, 2011, Bechtel has received $67 million of the $72 million total settlement. The remaining milestone payments are tied to final acceptance of the units. In addition, Bechtel received 120 days of schedule relief for OC 1 and 60 days for OC 2. Therefore, the guaranteed in-service date of September 29, 2009 for OC 1 was extended to January 27, 2010, and the guaranteed in-service date of September 29, 2010 for OC 2 was extended to November 28, 2010. Bechtel subsequently received an additional 21 days of schedule relief for OC 2 as part of a change order signed concurrent with the turnover of OC 2. Therefore, the total schedule relief granted to Bechtel was 120 days for OC 1 and 81 days for OC 2.

We are responsible for approximately 85% of amounts paid under the Settlement Agreement, consistent with our ownership share of the Oak Creek expansion. The other joint owners are responsible for the remainder.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. We do not anticipate further charges as a result of the settlement, other than certain process-related costs we expect to incur to implement the settlement. We expect the court to provide final approval of the settlement agreement in April 2012, and to pay additional benefits to class members promptly after receiving this approval.

S -- SUPPLEMENTAL CASH FLOW INFORMATION

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. During the year ended December 31, 2010, we paid $198.0 million in interest, net of amounts capitalized, and $166.7 million in income taxes, net of refunds. During the year ended December 31, 2009, we paid $152.3 million in interest, net of amounts capitalized, and received $27.9 million in net refunds from income taxes.

As of December 31, 2011, 2010 and 2009, the amount of accounts payable related to capital expenditures was $16.7 million, $18.2 million and $14.7 million, respectively.

During the years ended December 31, 2011, 2010 and 2009, total amortization of deferred revenue was $54.4 million, $34.6 million and $8.0 million, respectively.

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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, 2011 and 2010, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 28, 2012

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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 internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 28, 2012

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 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, 2011.

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, 2011. 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 2011 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	2011	2010	2009	2008	2007
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 512.8	$ 454.4	$ 375.7	$ 355.1	$ 332.4
Earnings per share - Continuing Operations					
Basic	$ 2.20	$ 1.94	$ 1.61	$ 1.52	$ 1.42
Diluted	$ 2.18	$ 1.92	$ 1.59	$ 1.50	$ 1.40
Dividends per share of common stock	$ 1.04	$ 0.80	$ 0.675	$ 0.54	$ 0.50
Operating revenues (Millions)					
Utility energy	$ 4,431.5	$ 4,165.3	$ 4,092.0	$ 4,395.5	$ 4,190.9
Non-utility energy	435.1	320.2	163.1	126.2	75.7
Eliminations and Other	(380.2)	(283.0)	(154.2)	(119.3)	(62.3)
Total operating revenues	$ 4,486.4	$ 4,202.5	$ 4,100.9	$ 4,402.4	$ 4,204.3
As of December 31 (Millions)					
Total assets	$ 13,862.1	$ 13,059.8	$ 12,697.9	$ 12,617.8	$ 11,720.3
Long-term debt (including current maturities) and capital lease obligations	$ 4,646.9	$ 4,405.4	$ 4,171.5	$ 4,136.5	$ 3,525.3
Common Stock Closing Price	$ 34.96	$ 29.43	$ 24.92	$ 20.99	$ 24.36

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2011	2010	2011	2010
Operating revenues	$ 1,328.7	$ 1,248.6	$ 991.7	$ 890.9
Operating income	295.6	228.4	174.4	163.3
Income from Continuing Operations	170.9	129.0	98.0	87.5
Income (loss) from Discontinued Operations	—	0.7	11.5	1.2
Total Net Income	$ 170.9	$ 129.7	$ 109.5	$ 88.7
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.73	$ 0.55	$ 0.42	$ 0.37
Discontinued operations	—	—	0.05	0.01
Total earnings per share (basic)	$ 0.73	$ 0.55	$ 0.47	$ 0.38
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.72	$ 0.55	$ 0.41	$ 0.37
Discontinued operations	—	—	0.05	—
Total earnings per share (diluted)	$ 0.72	$ 0.55	$ 0.46	$ 0.37

	September		December	
Three Months Ended	2011	2010	2011	2010
Operating revenues	$ 1,052.8	$ 973.2	$ 1,113.2	$ 1,089.8
Operating income	224.3	203.0	193.0	215.7
Income from Continuing Operations	129.8	112.3	114.1	125.6
Income (loss) from Discontinued Operations	—	(0.1)	1.9	0.3
Total Net Income	$ 129.8	$ 112.2	$ 116.0	$ 125.9
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.56	$ 0.48	$ 0.49	$ 0.54
Discontinued operations	—	—	0.01	—
Total earnings per share (basic)	$ 0.56	$ 0.48	$ 0.50	$ 0.54
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.55	$ 0.47	$ 0.49	$ 0.53
Discontinued operations	—	—	0.01	—
Total earnings per share (diluted)	$ 0.55	$ 0.47	$ 0.50	$ 0.53

(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

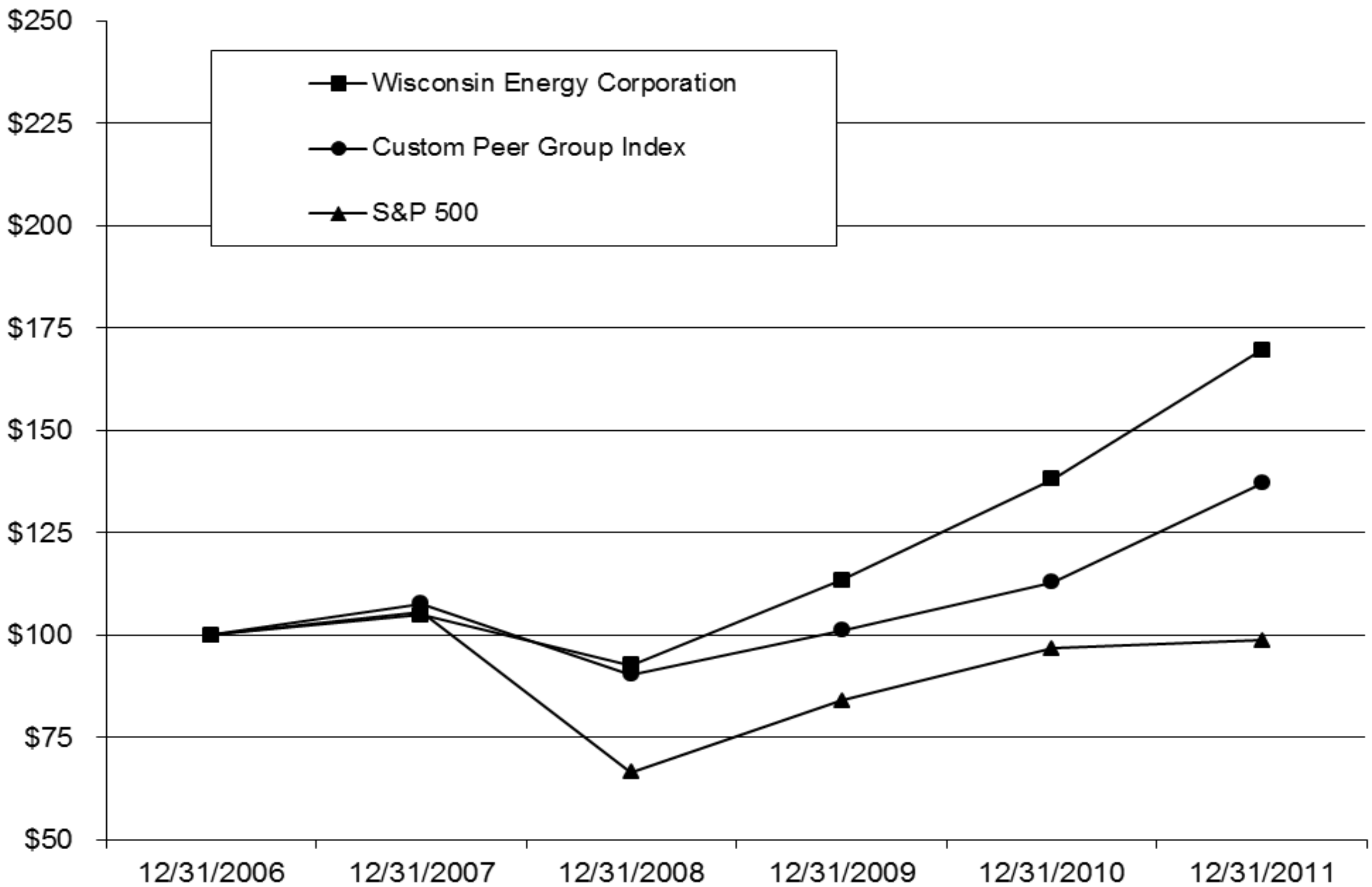
The performance graph on the next page shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2006, in each of:

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

Custom Peer Group Index. We use the Custom Peer Group Index for peer comparison purposes because we believe the Index provides an accurate representation of our peers. The Custom Peer Group Index is a market-capitalization-weighted index consisting of 27 companies, including Wisconsin Energy. These companies are similar to us in terms of business model and long-term strategies.

In addition to Wisconsin Energy, the companies in the Custom Peer Group Index are Allegheny Energy, Inc.; 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; Integrys Energy Group, Inc.; NiSource Inc.; Northeast Utilities; Nstar; NV Energy, Inc.; OGE Energy Corp.; Pepco Holdings, Inc.; PG&E Corporation; Pinnacle West Capital Corporation; Portland General; Progress Energy Inc.; SCANA Corporation; Sempra Energy; The Southern Company; Westar Energy, Inc.; and Xcel Energy Inc.

Five-Year Cumulative Return Chart



Value of Investment at Year-End

	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11
Wisconsin Energy Corporation	$100	$105	$93	$113	$138	$170
Custom Peer Group Index	$100	$108	$90	$101	$113	$137
S&P 500	$100	$105	$66	$84	$97	$99

MARKET FOR OUR COMMON
EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2011, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 42,550 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC." Daily trading prices and volume can be found in the "NYSE Composite" section of most major newspapers, usually abbreviated as WI Engy.

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 I -- Common Equity in the Notes to Consolidated Financial Statements.

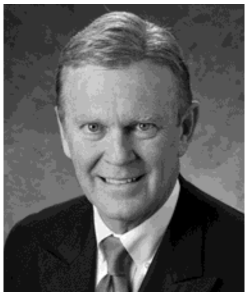
On January 19, 2012, our Board of Directors approved a new dividend policy. Pursuant to this new policy, we will target a dividend payout ratio that trends toward 60% in the year 2014. At the same time, in accordance with that policy, our Board of Directors increased our quarterly dividend to $0.30 per share effective with the first quarter 2012 dividend payment, which would result in annual dividends of $1.20 per share.

On January 20, 2011, our Board of Directors approved a two-for-one stock split of our common stock, which was effected through a stock dividend. Stockholders of record at the close of business on February 14, 2011 were entitled to one additional share of Wisconsin Energy common stock for each share then owned. The additional shares were distributed on March 1, 2011. The table below reflects the impact of the two-for-one stock split.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2011			2010		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$ 31.01	$ 28.83	$ 0.26	$ 25.71	$ 23.44	$ 0.20
Second	$ 31.89	$ 29.39	0.26	$ 26.90	$ 23.42	0.20
Third	$ 32.49	$ 27.00	0.26	$ 29.29	$ 24.71	0.20
Fourth	$ 35.38	$ 29.82	0.26	$ 30.51	$ 28.76	0.20
Annual	$ 35.38	$ 27.00	$ 1.04	$ 30.51	$ 23.42	$ 0.80

BOARD OF DIRECTORS

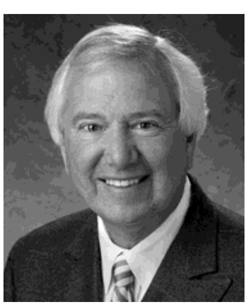


John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

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.

Robert A. Cornog
Director since 1993.
Retired Chairman of the Board, President and Chief Executive Officer of Snap-on Incorporated, a developer, manufacturer and distributor of professional hand and power tools, diagnostic and shop equipment and tool storage products.



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 of the Board, President and Chief Executive Officer of Wisconsin Energy Corporation.

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 Robert W. Baird & Co. Incorporated; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Robert W. Baird & Co. provides wealth management, capital markets, private equity and asset management services to clients worldwide.

Frederick P. Stratton, Jr.
Director since 1987.
Chairman Emeritus of Briggs & Stratton Corporation, a manufacturer of small gasoline engines.

OFFICERS

The names and positions as of December 31, 2011 of Wisconsin Energy's officers are listed below.

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

James C. Fleming[1][2] – Executive Vice President and General Counsel.

Frederick D. Kuester[1] – Executive Vice President and Chief Financial Officer.

Allen L. Leverett[1] – Executive Vice President.

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

Kristine A. Rappé[1] – Senior Vice President and Chief Administrative Officer.

Darnell K. DeMasters – Vice President – Federal Policy.

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

J. Patrick Keyes – Vice President and Treasurer.

Walter J. Kunicki – Vice President.

Susan H. Martin[2] – Vice President, Corporate Secretary and Associate General Counsel.

Richard J. White – Vice President.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

Scott J. Lauber – Assistant Treasurer.

James A. Schubilske – Assistant Treasurer.

[1] Executive Officers of Wisconsin Energy Corporation as of December 31, 2011. Charles R. Cole and Kevin Fletcher, both Senior Vice Presidents of Wisconsin Electric Power Company and Wisconsin Gas LLC, are also executive officers of Wisconsin Energy Corporation. Mr. Cole retired effective March 1, 2012.

[2] Mr. Fleming stepped down as General Counsel effective March 1, 2012, and is retiring effective April 1, 2012. Ms. Martin was appointed Executive Vice President, General Counsel and Corporate Secretary effective March 1, 2012.

STOCKHOLDER INFORMATION

ACCOUNT INFORMATION

- Visit **www.bnymellon.com/shareowner/equityaccess**. Wisconsin Energy's transfer agent, BNY Mellon Shareowner Services, 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 MLink[sm], the paperless communication program from BNY Mellon. MLink also features electronic delivery of your annual meeting materials.

- Write to:
  Wisconsin Energy Corporation
  c/o BNY Mellon Shareowner Services
  P.O. Box 358035
  Pittsburgh, PA 15252-8035

- Call BNY Mellon Shareowner Services 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 WEC common stock and reinvest dividends. To review the Prospectus and enroll, go to **wisconsinenergy.com** and select the Investors tab. You also may contact BNY Mellon Shareowner Services 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 BNY Mellon Shareowner Services 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.

DUPLICATE MAILINGS

To combine accounts or to discontinue multiple mailings of the proxy statement and annual report, contact BNY Mellon Shareowner Services.

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, 2011. The certification of Wisconsin Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange corporate governance listing standards will be filed with the NYSE following the 2012 Annual Meeting of Stockholders. Last year, we filed this certification with the NYSE on June 3, 2011.

CORPORATE GOVERNANCE

Wisconsin Energy has a long tradition of sound corporate governance practices. The company continues to rank at or near the top of more than 4,300 companies rated for governance practices by GovernanceMetrics International (GMI), an independent rating agency. Over an eight-year period, Wisconsin Energy earned a perfect 10 rating 27 consecutive times, the only company worldwide to achieve this distinction.

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 impact. For additional information, visit **www.wisconsinenergy.com/csr/**.

Wisconsin Energy Corporation

Wisconsin Energy Corporation

231 W. MICHIGAN ST.

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414-221-2345

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