
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 10-K

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

For the Fiscal Year Ended **December 31, 2010**

<u>Commission File Number</u>	<u>Registrant; State of Incorporation Address; and Telephone Number</u>	<u>IRS Employer Identification No.</u>
001-01245	WISCONSIN ELECTRIC POWER COMPANY (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 2046 Milwaukee, WI 53201 (414) 221-2345	39-0476280

Securities Registered Pursuant to Section 12(b) of the Act: None

Securities Registered Pursuant to Section 12(g) of the Act:
Serial Preferred Stock, 3.60% Series, \$100 Par Value
Six Per Cent. Preferred Stock, \$100 Par Value

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

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

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

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

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

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

Large accelerated filer

Accelerated filer

Non-accelerated filer (Do not
check if a smaller reporting company)

Smaller reporting company

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

As of June 30, 2010 (and currently), all of the common stock of Wisconsin Electric Power Company is held by Wisconsin Energy Corporation.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2011):

Common Stock, \$10 Par Value, 33,289,327 shares outstanding

Documents Incorporated by Reference

Portions of Wisconsin Electric Power Company's Definitive information statement on Schedule 14C for its Annual Meeting of Stockholders, to be held on April 28, 2011, are incorporated by reference into Part III hereof.

WISCONSIN ELECTRIC POWER COMPANY
FORM 10-K REPORT FOR THE YEAR ENDED DECEMBER 31, 2010

TABLE OF CONTENTS

<u>Item</u>	<u>Page</u>
<u>PART I</u>	
1. Business	10
1A. Risk Factors	23
1B. Unresolved Staff Comments	29
2. Properties	30
3. Legal Proceedings	31
4. [Removed and Reserved]	32
Executive Officers of the Registrant	32
<u>PART II</u>	
5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	34
6. Selected Financial Data	35
7. Management's Discussion and Analysis of Financial Condition and Results of Operations .	36
7A. Quantitative and Qualitative Disclosures About Market Risk	66
8. Financial Statements and Supplementary Data	67
Consolidated Income Statements.....	67
Consolidated Balance Sheets -- Assets.....	68
Consolidated Balance Sheets -- Capitalization and Liabilities.....	69
Consolidated Statements of Cash Flows.....	70
Consolidated Statements of Capitalization.....	71
Consolidated Statements of Common Equity.....	72
Notes to Consolidated Financial Statements.....	73
Note A Summary of Significant Accounting Policies.....	73
Note B Recent Accounting Pronouncements.....	76
Note C Regulatory Assets and Liabilities.....	76
Note D Divestitures.....	77
Note E Asset Retirement Obligations.....	78
Note F Variable Interest Entities.....	78
Note G Income Taxes.....	79
Note H Common Equity.....	81
Note I Long-Term Debt and Capital Lease Obligations.....	85
Note J Short-Term Debt.....	88
Note K Derivative Instruments.....	88
Note L Fair Value Measurements.....	89
Note M Benefits.....	91
Note N Guarantees.....	97

<u>Item</u>	<u>Page</u>
Note O Segment Reporting.....	97
Note P Related Parties.....	99
Note Q Commitments and Contingencies.....	100
Note R Supplemental Cash Flow Information.....	101
Note S Subsequent Events.....	102
Report of Independent Registered Public Accounting Firm.....	103
9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	104
9A. Controls and Procedures	104
9B. Other Information	104
 <u>PART III</u> 	
10. Directors, Executive Officers and Corporate Governance of the Registrant	105
11. Executive Compensation	105
12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	105
13. Certain Relationships and Related Transactions, and Director Independence	106
14. Principal Accountant Fees and Services	106
 <u>PART IV</u> 	
15. Exhibits and Financial Statement Schedules	106
Schedule II - Valuation and Qualifying Accounts	108
Signatures	109
Exhibit Index	E-1

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 Subsidiary and Affiliates

Bostco	Bostco LLC
We Power	W.E. Power, LLC
Wisconsin Energy	Wisconsin Energy Corporation
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

Other Affiliates

ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, 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
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CAVR	Clean Air Visibility Rule
CO ₂	Carbon Dioxide
FIP	Federal Implementation Plan
MACT	Maximum Achievable Control Technology
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NO _x	Nitrogen Oxide
PM _{2.5}	Fine Particulate Matter
RACT	Reasonably Available Control Technology

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS - (Cont'd)

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

SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
VOC	Volatile Organic Compounds
WPDES	Wisconsin Pollution Discharge Elimination System

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 of Wisconsin Energy
CPCN	Certificate of Public Convenience and Necessity
Energy Policy Act	Energy Policy Act of 2005
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
Guardian	Guardian Pipeline L.L.C.
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSEs	Load Serving Entities
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	<i>Power the Future</i>
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
Settlement Agreement	Settlement Agreement and Release between Elm Road Services, LLC 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

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS - (Cont'd)

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

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
CWIP	Construction Work in Progress
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," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "should" 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; 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; 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; 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 Wisconsin Energy Corporation's (Wisconsin Energy) *Power the Future* (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, 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; 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 under the Energy Policy Act 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.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION - (Cont'd)

- Internal restructuring options that may be pursued by Wisconsin Energy.
- Current and future litigation, regulatory investigations, proceedings or inquiries, including the pending lawsuit against the Wisconsin Energy Corporation Retirement Account Plan (Plan), FERC matters, and IRS audits and other tax matters.
- Events in the global credit markets that may affect the availability and cost of capital.
- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or our subsidiary; and our credit ratings.
- The investment performance of Wisconsin Energy's 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 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.
- 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, including the risk factors set forth in Item 1A of this report.

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.

PART I

ITEM 1. BUSINESS

INTRODUCTION

Wisconsin Electric Power Company, a subsidiary of Wisconsin Energy, was incorporated in the state of Wisconsin in 1896. We maintain our principal executive offices in Milwaukee, Wisconsin. Unless qualified by their context when used in this document, the terms Wisconsin Electric, the Company, our, us or we refer to Wisconsin Electric Power Company and its subsidiary, Bostco LLC (Bostco).

We conduct our operations primarily in three operating segments: an electric utility segment, a natural gas utility segment and a steam utility segment. We serve approximately 1,120,200 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 464,300 gas customers in Wisconsin and approximately 460 steam customers in metropolitan Milwaukee, Wisconsin. For further financial information about our business segments, see Results of Operations in Item 7 and Note O -- Segment Reporting in the Notes to Consolidated Financial Statements in Item 8.

Wisconsin Energy is also the parent company of Wisconsin Gas LLC (Wisconsin Gas), a natural gas distribution utility, which serves customers throughout Wisconsin; and W.E. Power, LLC (We Power), an unregulated company that was formed in 2001 to design, construct, own and lease to us the new generating capacity included in Wisconsin Energy's PTF strategy. We have combined common functions with Wisconsin Gas and operate under the trade name of "We Energies."

Bostco is our non-utility subsidiary that develops and invests in real estate. As of December 31, 2010, Bostco had \$35.1 million of assets.

Our annual and periodical filings with the SEC are available, free of charge, through Wisconsin Energy's Internet website www.wisconsinenergy.com. These documents are available as soon as reasonably practicable after such materials are filed (or furnished) with the SEC.

UTILITY OPERATIONS

ELECTRIC UTILITY OPERATIONS

We are the largest electric utility in the state of Wisconsin. We generate and distribute electric energy in a territory that includes southeastern (including the metropolitan Milwaukee area), east central and northern Wisconsin and in the Upper Peninsula of Michigan.

We participate in the MISO Energy Markets. The competitiveness of our generation offered in the MISO Energy Markets affects how our generating units are dispatched and how we buy and sell power. For further information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Sales

Our electric energy sales to all classes of customers totaled approximately 30.5 million MWh during 2010 and approximately 28.9 million MWh during 2009. We had approximately 1,120,200 electric customers as of December 31, 2010 and 1,117,400 electric customers as of December 31, 2009.

We are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits, Certificates of Public Convenience and Necessity (CPCNs) or boundary agreements with other utilities, and in certain territories in the state of Michigan pursuant to franchises granted by municipalities. We also sell wholesale electric power within the MISO Energy Markets.

Electric Sales Growth: Our service territory experienced growth in 2010 after the significant economic recession that occurred during late 2008 and into 2009. Our normalized 2010 electric retail sales, excluding our two largest customers, two iron ore mines, were approximately 0.2% higher than our

ITEM 1. BUSINESS - (Cont'd)

normalized 2009 electric sales. As we look toward 2011 and beyond, we presently anticipate total retail and municipal electric kWh sales will grow at an annual rate of 0.5% to 1.0% over the next five years. This estimate assumes normal weather and excludes the two iron ore mines.

Sales to Large Electric Retail Customers: We provide electric utility service to a diversified base of customers in such industries as mining, paper, foundry, food products and machinery production, as well as to large retail chains.

Our largest retail electric customers are two iron ore mines located in the Upper Peninsula of Michigan. The combined electric energy sales to the two mines accounted for 6.9% and 5.3% of our total electric utility energy sales during 2010 and 2009, respectively.

Sales to Wholesale Customers: During 2010, we sold wholesale electric energy to one municipally owned system, two rural cooperatives and two municipal joint action agencies located in the states of Wisconsin and Michigan. Our wholesale electric energy sales were also made to fourteen other public utilities and power marketers throughout the region under rates approved by FERC. Wholesale sales accounted for approximately 10.2% of our total electric energy sales and 6.0% of total electric operating revenues during 2010, compared with 10.7% of total electric energy sales and 6.1% of total electric operating revenues during 2009.

Electric System Reliability Matters: Our electric sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. The Public Service Commission of Wisconsin (PSCW) has planning reserve requirements consistent with the MISO calculated planning reserve margin. The Michigan Public Service Commission (MPSC) has not yet established guidelines in this area. In accordance with the MISO calculated planning reserve margin requirements, we had adequate capacity to meet all of our firm electric load obligations during 2010 and expect to have adequate capacity to meet all of our firm obligations during 2011. For additional information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Supply

Our electric supply strategy is to provide our customers with a diverse fuel mix that is expected to maintain a stable, reliable and affordable supply of electricity. We supply a significant amount of electricity to our customers from power plants that we own or lease. We supplement our internally generated power supply with long-term power purchase agreements, including the Point Beach Nuclear Power Plant (Point Beach) power purchase agreement discussed later in this report, and through spot purchases in the MISO Energy Markets.

ITEM 1. BUSINESS - (Cont'd)

Our installed capacity by fuel type as of December 31 is shown below:

	Dependable Capability in MW (a)		
	2010	2009	2008
Coal (b)	3,646	3,131	3,247
Natural Gas - Combined Cycle	1,090	1,090	1,090
Natural Gas/Oil - Peaking Units (c)	1,150	1,150	1,138
Renewables (d)	86	86	86
Total	<u>5,972</u>	<u>5,457</u>	<u>5,561</u>

- (a) Dependable capability is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. The values were established by test and may change slightly from year to year.
- (b) The increase in 2010 as compared to 2009 reflects the February 2010 in-service date of Oak Creek expansion Unit 1 (OC 1), and our share of this unit's dependable capability, which is 515 MW. In addition, in January 2011, Oak Creek expansion Unit 2 (OC 2) was placed in service and our share of this unit's dependable capability is 515 MW.
- (c) The dual-fueled facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local gas distribution company that delivers gas to the plants.
- (d) Includes hydroelectric and wind generation. For purposes of measuring dependable capability, the 145 MW Blue Sky Green Field wind project has a dependable capability of 29 MW.

The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, 2010, as well as an estimate for 2011:

	Estimate	Actual		
	2011	2010	2009	2008
Coal	55.8%	53.9%	52.8%	57.3%
Wind	1.1%	1.0%	1.2%	0.6%
Hydroelectric	1.2%	1.0%	0.8%	0.9%
Natural Gas - Combined Cycle	6.8%	8.4%	7.6%	5.3%
Natural Gas/Oil - Peaking Units	0.2%	0.3%	0.2%	0.3%
Net Generation	65.1%	64.6%	62.6%	64.4%
Purchased Power	34.9%	35.4%	37.4%	35.6%
Total	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>

Our average fuel and purchased power costs per MWh by fuel type for the years ended December 31 are shown below:

	2010	2009	2008
Coal	\$ 26.44	\$ 25.01	\$ 22.93
Natural Gas - Combined Cycle	\$ 43.14	\$ 51.67	\$ 69.65
Natural Gas/Oil - Peaking Units	\$ 97.36	\$121.18	\$160.25
Purchased Power	\$ 43.11	\$ 42.21	\$ 46.67

Historically, the fuel costs for coal have been under long-term contracts, which helped with price stability. Coal and associated transportation services have seen greater volatility in pricing than previously experienced in these markets due to changes in the domestic and world-wide demand for coal and the impacts of diesel costs which are incorporated into fuel surcharges on rail transportation.

ITEM 1. BUSINESS - (Cont'd)

Natural gas costs have been volatile. We had a PSCW-approved hedging program to help manage our natural gas price risk, which expired on December 31, 2010. We have requested PSCW approval to continue this hedging program. This hedging program is generally implemented on a 36-month forward-looking basis. Proceeds related to the natural gas hedging program are reflected in the average costs of natural gas and purchased power shown above.

Coal-Fired Generation

Our coal-fired generation consists of 18 generating units as of December 31, 2010, including OC 1 which was placed in service in February 2010. In addition, OC 2 was placed in service in January 2011.

Coal Supply: We diversify the coal supply for our power plants by purchasing coal from mines in Wyoming, Pennsylvania and Colorado as well as from various other states. During 2011, 100% of our projected coal requirements of 11.2 million tons are under contracts which are not tied to 2011 market pricing fluctuations. In 2010, our coal-fired generation consisted of seven operating plants with a dependable capability of approximately 3,646 MW. However, by the end of 2011, with the addition of OC 2, we expect our coal-fired generation to have a dependable capability of 4,161 MW.

The annual tonnage amounts contracted for 2011 through 2013 are as follows:

<u>Contract Expiration Date</u>	<u>Annual Tonnage (Thousands)</u>
Dec. 2011	11,214
Dec. 2012	9,522
Dec. 2013	3,340

Coal Deliveries: Approximately 96% of our 2011 coal requirements are expected to be delivered by unit trains owned or leased by us. The unit trains will transport coal for the Oak Creek and Pleasant Prairie Power Plants from Wyoming mines, and transport coal for the Oak Creek expansion units from Pennsylvania and West Virginia. Coal from Colorado mines is transported via rail to Lake Superior or Lake Michigan transfer docks and delivered by lake vessel to the Milwaukee harbor for Milwaukee-based power plants. Montana and Wyoming coal for the Presque Isle Power Plant is transported via rail to Superior, Wisconsin, placed in dock storage and reloaded into lake vessels for plant delivery. Colorado coal bound for the Presque Isle Power Plant is shipped via rail to Lake Superior and Lake Michigan (Chicago) coal transfer docks, respectively, for lake vessel delivery to the plant.

Certain of our coal transportation contracts contain fuel cost adjustments that are tied to changes in a diesel fuel price index. Currently, diesel fuel contracts are not actively traded; therefore, we are using financial heating oil contracts to mitigate risk. We had a PSCW-approved hedging program that allowed us to hedge up to 75% of our potential fuel for electric generation in order to help manage our risk of higher delivered cost of coal. This hedging program expired on December 31, 2010. We have requested PSCW approval to continue this program. The costs of this program are included in our fuel and purchased power costs.

Edgewater Generating Unit 5: During the fourth quarter of 2009, we reached a contingent agreement to sell 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. In March 2010, the agreement became effective and we are in the process of receiving regulatory approvals. We received approval for the sale from FERC in June 2010, and from the PSCW in November 2010. We are currently working with the MPSC to obtain approval on terms that are acceptable to us. Assuming completion of the sale, we expect to realize proceeds of between \$40 million and \$45 million depending on the working capital balances and our level of capital investment in the unit prior to the sale. The contractual deadline to complete the sale is June 30, 2011.

ITEM 1. BUSINESS - (Cont'd)

Environmental Matters: For information regarding emission restrictions, especially as they relate to coal-fired generating facilities, see Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7.

Natural Gas-Fired Generation

Our natural gas-fired generation consists of four operating plants with a dependable capability of approximately 1,983 MW as of December 31, 2010. We added Port Washington Generating Station Unit 1 (PWGS 1) and Port Washington Generating Station Unit 2 (PWGS 2), both natural gas-fired units with a dependable capability of 545 MW each, in July 2005 and May 2008, respectively, via leases from We Power.

We purchase natural gas for these plants on the spot market from gas marketers, utilities and producers and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, balancing and storage agreements intended to support the plants' variable usage.

We had a PSCW-approved hedging program that allowed us to hedge up to 75% of our estimated gas usage for electric generation in order to help manage our natural gas price risk. This hedging program expired on December 31, 2010. We have requested PSCW approval to continue this program. The costs of this program are included in our fuel and purchased power costs.

Oil-Fired Generation

Fuel oil is used for the combustion turbines at the Germantown Power Plant units 1-4, boiler ignition and flame stabilization at the Presque Isle Power Plant, and diesel engines at the Pleasant Prairie Power Plant and Valley Power Plant. Our oil-fired generation had a dependable capability of approximately 257 MW as of December 31, 2010. Our natural gas-fired peaking units have the ability to burn oil if natural gas is not available due to delivery constraints. Fuel oil requirements are purchased under agreements with suppliers.

Renewable Generation

Hydroelectric: Our hydroelectric generating system consists of 13 operating plants with a total installed capacity of approximately 88 MW and a dependable capability of approximately 57 MW as of December 31, 2010. Of these 13 plants, 12 plants (86 MW of installed capacity) have long-term licenses from FERC. The thirteenth plant, with an installed generating capacity of approximately 2 MW, does not require a license.

Wind: We completed the Blue Sky Green Field wind project in May 2008. This project has 88 turbines, an installed capacity of approximately 145 MW and a current dependable capability of approximately 29 MW. In July 2008, we completed the purchase of rights to a new wind farm site in Central Wisconsin, Glacier Hills Wind Park, and filed a request for a CPCN with the PSCW in October 2008. The PSCW approved the CPCN in January 2010. We currently expect to install 90 wind turbines with a total generating capacity of approximately 162 MW. This project is expected to cost between \$360 million and \$370 million, excluding Allowance for Funds Used During Construction (AFUDC). Construction commenced in May 2010, and we anticipate 2012 will be the first full year of operation.

Biomass: In September 2009, we announced plans to construct 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 electricity and will also support Domtar's sustainable papermaking operations. We believe the biomass plant will be eligible for the federal production tax credit. We currently expect to invest approximately \$255 million, excluding AFUDC, in the plant and for it to be completed during the fall of 2013, subject to regulatory and other approvals. In March 2010, we filed a request for a Certificate of Authority for the project with the PSCW. We anticipate a decision from the PSCW during the first quarter of 2011.

ITEM 1. BUSINESS - (Cont'd)**Power Purchase Commitments**

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. The following table identifies our power purchase commitments as of December 31, 2010 with unaffiliated parties for the next five years:

Year	MW Under Power Purchase Commitments (a)
2011	1,599
2012	1,440
2013	1,269
2014	1,269
2015	1,269

(a) MW do not include leased generation from PTF units.

Approximately 1,030 MW per year relates to the Point Beach long-term power purchase agreement. Under this agreement, we pay a predetermined price per MWh for energy delivered according to a schedule included in the agreement. The balance of these power purchase commitments are tolling arrangements whereby we are responsible for the procurement, delivery and the cost of natural gas fuel related to specific units identified in the contracts.

Electric Transmission and Energy Markets

American Transmission Company: ATC owns, maintains, monitors and operates electric transmission systems in Wisconsin, Michigan and Illinois. ATC's sole business is to provide reliable, economic electric transmission service to all customers in a fair and equitable manner. ATC is expected to provide comparable service to all customers, including us, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and we are a non-transmission owning member and customer of MISO. We owned approximately 23.0% of ATC as of December 31, 2010 and 2009.

MISO: In connection with its status as a FERC approved Regional Transmission Organization (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 the ancillary services market. For further information on MISO and the MISO Energy Markets, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition - Electric Transmission and Energy Markets in Item 7.

ITEM 1. BUSINESS - (Cont'd)**Electric Utility Operating Statistics**

The following table shows certain electric utility operating statistics for the past five years:

SELECTED CONSOLIDATED ELECTRIC UTILITY OPERATING DATA					
Year Ended December 31	2010	2009	2008	2007	2006
Operating Revenues (Millions)					
Residential	\$1,114.3	\$977.6	\$962.5	\$915.5	\$870.8
Small Commercial/Industrial	922.2	860.3	869.7	840.6	796.0
Large Commercial/Industrial	677.1	599.4	646.3	664.2	637.0
Other - Retail	21.9	21.2	20.8	19.2	18.9
Total Retail Sales	<u>2,735.5</u>	<u>2,458.5</u>	<u>2,499.3</u>	<u>2,439.5</u>	<u>2,322.7</u>
Wholesale - Other	134.6	116.7	77.7	83.5	68.1
Resale - Utilities	40.4	47.5	37.7	110.7	73.5
Other Operating Revenues	25.8	62.3	45.9	40.9	35.2
Total Operating Revenues	<u><u>\$2,936.3</u></u>	<u><u>\$2,685.0</u></u>	<u><u>\$2,660.6</u></u>	<u><u>\$2,674.6</u></u>	<u><u>\$2,499.5</u></u>
MWh Sales (Thousands)					
Residential	8,426.3	7,949.3	8,277.1	8,416.1	8,154.0
Small Commercial/Industrial	8,823.3	8,571.6	9,023.7	9,185.4	8,899.0
Large Commercial/Industrial	9,961.5	9,140.3	10,691.7	11,036.7	10,972.2
Other - Retail	155.3	156.5	161.5	162.4	163.7
Total Retail Sales	<u>27,366.4</u>	<u>25,817.7</u>	<u>28,154.0</u>	<u>28,800.6</u>	<u>28,188.9</u>
Wholesale - Other	2,004.6	1,529.4	2,620.7	1,939.6	1,819.0
Resale - Utilities	1,103.8	1,548.9	881.0	1,920.7	1,436.2
Total Sales	<u><u>30,474.8</u></u>	<u><u>28,896.0</u></u>	<u><u>31,655.7</u></u>	<u><u>32,660.9</u></u>	<u><u>31,444.1</u></u>
Customers - End of Year (Thousands)					
Residential	1,003.6	1,001.2	999.1	995.6	990.4
Small Commercial/Industrial	113.5	113.1	112.6	110.8	108.7
Large Commercial/Industrial	0.7	0.7	0.7	0.7	0.7
Other	2.4	2.4	2.4	2.4	2.4
Total Customers	<u><u>1,120.2</u></u>	<u><u>1,117.4</u></u>	<u><u>1,114.8</u></u>	<u><u>1,109.5</u></u>	<u><u>1,102.2</u></u>
Customers - Average (Thousands)	1,118.7	1,115.5	1,111.8	1,105.5	1,097.6
<u>Degree Days (a)</u>					
Heating (6,612 Normal)	6,183	6,825	7,073	6,508	6,043
Cooling (698 Normal)	944	475	593	800	723

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

ITEM 1. BUSINESS - (Cont'd)**GAS UTILITY OPERATIONS**

We are authorized to provide retail gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits, CPCNs or boundary agreements with other utilities. We also transport customer-owned gas. Our gas utility operates in three distinct service areas: west and south of the City of Milwaukee, the Appleton area and areas within Iron and Vilas Counties, Wisconsin.

Gas Deliveries

Our gas utility business is highly seasonal due to the heating requirements of residential and commercial customers. Annual gas sales are also impacted by the variability of winter temperatures.

Total gas therms delivered, including customer-owned transported gas, were approximately 812.6 million therms during 2010, a 5.8% decrease compared with 2009. As of December 31, 2010, we were transporting gas for approximately 400 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 37.0% of the total volumes delivered during 2010, 34.6% during 2009 and 34.8% during 2008. We had approximately 464,300 and 462,400 gas customers as of December 31, 2010 and 2009, respectively. Our peak daily send-out during 2010 was 588,818 Dth on January 28, 2010.

Sales to Large Gas Customers: We provide gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include the paper, food products and fabricated metal products industries. Fuel used for our electric generation represents our largest transportation customer.

Gas Deliveries Growth: We currently forecast total retail therm deliveries (excluding natural gas deliveries for generation) to stay flat over the five-year period ending December 31, 2015 as new customer additions are expected to be offset by a reduction in the average use per customer. This forecast reflects a current year normalized sales level and normal weather.

Competition

Competition in varying degrees exists between natural gas and other forms of energy available to consumers. A number of our large commercial and industrial customers are dual-fuel customers that are equipped to switch between natural gas and alternate fuels. We are allowed to offer lower-priced gas sales and transportation services to dual-fuel customers. Under gas transportation agreements, customers purchase gas directly from gas marketers and arrange with interstate pipelines and us to have the gas transported to their facilities. We earn substantially the same margin (difference between revenue and cost of gas) whether we sell and transport gas to customers or only transport their gas.

Our ability to maintain our share of the industrial dual-fuel market depends on our success and the success of third-party gas marketers in obtaining long-term and short-term supplies of natural gas at competitive prices compared to other sources and in arranging or facilitating competitively-priced transportation service for those customers that desire to buy their own gas supplies.

Federal and state regulators continue to implement policies to bring more competition to the gas industry. While the gas utility distribution function is expected to remain a highly regulated, monopoly function, the sale of the natural gas commodity and related services are expected to remain subject to competition from third parties. It remains uncertain if and when the current economic disincentives for small customers to choose an alternative gas commodity supplier may be removed such that we begin to face competition for the sale of gas to our smaller firm customers.

Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers despite periods of severe cold in recent heating seasons.

ITEM 1. BUSINESS - (Cont'd)

Pipeline Capacity and Storage: The interstate pipelines serving Wisconsin originate in major gas producing areas of North America: the Oklahoma and Texas basins, the Gulf of Mexico, western Canada and the Rocky Mountains. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio. We have extended our commitment on Guardian Pipeline L.L.C.'s (Guardian) original pipeline through December 2022. We have committed to purchase additional capacity through March 2024 on a new Guardian pipeline extension that was completed during 2009.

Due to the daily and seasonal variations in gas usage in Wisconsin, we have also contracted for substantial underground storage capacity, primarily in Michigan. Storage capacity, along with our gas purchase contracts, enables us to manage significant changes in daily demand and to optimize our overall gas supply and capacity costs. We generally inject gas into storage during the spring and summer months when demand is lower and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity during periods of peak usage than would otherwise be necessary and can purchase gas on a more uniform daily basis from suppliers year-round. Each of these capabilities enables us to reduce our overall costs.

We hold firm daily transportation and storage capacity entitlements from pipelines and other service providers under long-term contracts.

Term Gas Supply: We have contracts for firm supplies with terms in excess of 30 days with suppliers for gas acquired in the Chicago, Illinois market hub and in the producing areas discussed above. The pricing of the term contracts is based upon first of the month indices. Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day demand.

Secondary Market Transactions: Capacity release is a mechanism by which pipeline long-line and storage capacity and gas supplies under contract can be resold in the secondary market. Local distribution companies, like our gas operations, must contract for capacity and supply sufficient to meet the firm peak-day demand of their customers. Peak or near peak demand days generally occur only a few times each year. Capacity release facilitates higher utilization of contracted capacity and supply during those times when the full contracted capacity and supply are not needed by the utility, helping to mitigate the fixed costs associated with maintaining peak levels of capacity and gas supply. Through pre-arranged agreements and day-to-day electronic bulletin board postings, interested parties can purchase this excess capacity and supply. The proceeds from these transactions are passed through to rate payers, subject to our approved Gas Cost Recovery Mechanism (GCRM). During 2010, we continued to participate in the capacity release market. See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7 for information on the GCRM.

Spot Market Gas Supply: We expect to continue to make gas purchases in the 30-day spot market as price and other circumstances dictate. We have supply relationships with a number of sellers from whom we purchase spot gas.

Hedging Gas Supply Prices: We have PSCW approval to hedge (i) up to 45% of planned flowing gas supply using New York Mercantile Exchange (NYMEX) based natural gas options and (ii) up to 15% of planned flowing gas supply using NYMEX based natural gas future contracts. Those approvals allow us to pass 100% of the hedging costs (premiums and brokerage fees) and proceeds (gains and losses) to rate payers through our GCRM. Hedge targets (volumes) are provided annually to the PSCW as part of our three-year gas supply plan and risk management filing.

To the extent that opportunities develop and our physical supply operating plans will support them, we also have PSCW approval to utilize NYMEX based natural gas derivatives to capture favorable forward market price differentials. That approval provides for 100% of the related proceeds to accrue to our GCRM.

ITEM 1. BUSINESS - (Cont'd)**Gas Utility Operating Statistics**

The following table shows certain gas utility operating statistics for the past five years:

SELECTED CONSOLIDATED GAS UTILITY OPERATING DATA					
Year Ended December 31	2010	2009	2008	2007	2006
Operating Revenues (Millions)					
Residential	\$310.6	\$365.9	\$445.8	\$390.0	\$363.5
Commercial/Industrial	151.3	189.7	238.5	202.8	191.7
Interruptible	3.1	3.5	6.0	5.2	4.6
Total Retail Gas Sales	465.0	559.1	690.3	598.0	559.8
Transported Gas	14.2	12.9	14.3	15.1	14.9
Other Operating Revenues	2.4	(7.8)	4.6	(1.2)	15.3
Total Operating Revenues	\$481.6	\$564.2	\$709.2	\$611.9	\$590.0
Therms Delivered (Millions)					
Residential	321.8	349.4	364.7	342.6	313.2
Commercial/Industrial	184.5	208.8	216.2	199.6	190.3
Interruptible	5.5	5.9	6.9	7.1	6.0
Total Retail Gas Sales	511.8	564.1	587.8	549.3	509.5
Transported Gas	300.8	298.4	313.3	333.7	303.1
Total Therms Delivered	812.6	862.5	901.1	883.0	812.6
Customers - End of Year (Thousands)					
Residential	425.6	423.8	422.0	419.1	415.1
Commercial/Industrial	38.3	38.2	38.1	37.7	37.1
Transported Gas	0.4	0.4	0.4	0.4	0.4
Total Customers	464.3	462.4	460.5	457.2	452.6
Customers - Average (Thousands)	462.9	460.8	458.3	454.5	449.1
<u>Degree Days (a)</u>					
Heating (6,612 Normal)	6,183	6,825	7,073	6,508	6,043

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

STEAM UTILITY OPERATIONS

Our steam utility generates, distributes and sells steam supplied by our Valley and Milwaukee County Power Plants. We operate a district steam system in downtown Milwaukee and the near south side of Milwaukee. Steam is supplied to this system from our Valley Power Plant, a coal-fired cogeneration facility. We also operate the steam production and distribution facilities of the Milwaukee County Power Plant located on the Milwaukee County Grounds in Wauwatosa, Wisconsin.

Annual sales of steam fluctuate from year to year based upon system growth and variations in weather conditions. During 2010, the steam utility had \$38.8 million of operating revenues from the sale of 2,740 million pounds of steam compared with \$39.1 million of operating revenues from the sale of 2,932 million pounds of steam during 2009. As of December 31, 2010 and 2009, steam was used by approximately 460 customers and 465 customers, respectively, for processing, space heating, domestic hot water and humidification.

ITEM 1. BUSINESS - (Cont'd)**UTILITY RATE MATTERS**

See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7.

REGULATION

We are a holding company by reason of our ownership interest in ATC, but are exempt from the requirements of the Public Utility Holding Company Act of 2005.

We are subject to the Energy Policy Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act, among other things, made electric utility industry consolidation more feasible, authorized FERC to review proposed mergers and the acquisition of generation facilities, changed the FERC regulatory scheme applicable to qualifying cogeneration facilities and modified certain other aspects of energy regulations and Federal tax policies applicable to us. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by FERC, which established mandatory electric reliability standards and which has the authority to levy monetary sanctions for failure to comply with these standards.

We are subject to the regulation of the PSCW as to retail electric, gas and steam rates in the state of Wisconsin, standards of service, issuance of securities, construction of certain new facilities, transactions with affiliates, billing practices and various other matters. We are also subject to the regulation of the PSCW as to certain levels of short-term debt obligations. We are subject to the regulation of the MPSC as to the various matters associated with retail electric service in the state of Michigan, except as to the issuance of securities in the ordinary course of business, construction of certain new facilities, levels of short-term debt obligations and advance approval of transactions with affiliates in the ordinary course of business. Our hydroelectric facilities are regulated by FERC. We are subject to the regulation of FERC with respect to wholesale power service, electric reliability requirements and accounting and with respect to our participation in the interstate natural gas pipeline capacity market. For information on how rates are set, see Rates and Regulatory Matters under Factors Affecting Results, Liquidity and Capital Resources in Item 7.

The following table compares the source of our operating revenues by regulatory jurisdiction for each of the three years in the period ended December 31, 2010:

	2010		2009		2008	
	Amount	Percent	Amount	Percent	Amount	Percent
	(Millions of Dollars)					
Wisconsin						
Electric Utility - Retail	\$2,568.3	74.3%	\$2,379.2	72.3%	\$2,416.8	70.8%
Gas Utility - Retail	481.6	13.9%	564.2	17.2%	709.2	20.8%
Steam Utility - Retail	38.8	1.1%	39.1	1.2%	40.3	1.2%
Total	<u>3,088.7</u>	<u>89.3%</u>	<u>2,982.5</u>	<u>90.7%</u>	<u>3,166.3</u>	<u>92.8%</u>
Michigan						
Electric Utility - Retail	193.0	5.6%	141.6	4.3%	128.4	3.8%
FERC						
Electric Utility - Wholesale	175.0	5.1%	164.2	5.0%	115.4	3.4%
Total Utility Operating Revenues	<u>\$3,456.7</u>	<u>100.0%</u>	<u>\$3,288.3</u>	<u>100.0%</u>	<u>\$3,410.1</u>	<u>100.0%</u>

Our operations are also subject to regulations, where applicable, of the United States Environmental Protection Agency (EPA), the Wisconsin Department of Natural Resources (WDNR), the Michigan Department of Environmental Quality and the Michigan Department of Natural Resources.

ITEM 1. BUSINESS - (Cont'd)**Public Benefits and Renewable Portfolio Standard**

Wisconsin Act 141 establishes a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. Under this act, we must meet certain minimum requirements for renewable energy generation. For the years 2010 through 2014, we must increase our percentage of total retail energy sales provided by renewable sources (renewable energy percentage) by at least two percentage points from our baseline renewable percentage of 2.27% to a level of 4.27%. Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003. As of December 31, 2010, our renewable energy percentage is at 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%. In addition, under this Act, 1.2% of utilities' annual operating revenues were required to be used to fund energy conservation programs through 2010. The funding required by Act 141 increased to 1.5% of annual operating revenues in 2011 and is scheduled to increase to 1.9% 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.

For additional information on Act 141 and current renewable projects, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters - Renewables, Efficiency and Conservation and Rates and Regulatory Matters - Renewable Energy Portfolio in Item 7.

ENVIRONMENTAL COMPLIANCE

Our operations are subject to extensive environmental regulations by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental statutes and regulations or revisions to existing laws, including for example, additional regulation of greenhouse gas emissions, coal combustion products, air emissions or wastewater discharges, could significantly increase these environmental compliance costs.

Expenditures for environmental compliance and remediation issues are included in anticipated capital expenditures described in Liquidity and Capital Resources in Item 7. For a discussion of additional environmental issues, see Environmental Matters in Item 3. For further information concerning air and water quality standards and rulemaking initiated by the EPA, including estimated costs of compliance, see Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7. For a discussion of matters related to certain solid waste and coal combustions product landfills, manufactured gas plant sites and air quality, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Compliance with federal, state and local environmental protection requirements resulted in capital expenditures of approximately \$215.5 million in 2010 compared with \$187.8 million in 2009. Expenditures incurred during 2010 and 2009 primarily included costs associated with the installation of pollution abatement facilities at our power plants. These expenditures are expected to be approximately \$158.6 million during 2011, reflecting Nitrogen Oxide (NO_x), Sulfur Dioxide (SO₂) and other pollution control equipment needed to comply with various rules promulgated by the EPA. Operation, maintenance and depreciation expenses for fly ash removal equipment and other environmental protection systems were approximately \$76.2 million and \$66.7 million during 2010 and 2009, respectively.

Coal Combustion Product Landfills

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. Some early designed and constructed coal combustion product landfills, which we used prior to

ITEM 1. BUSINESS - (Cont'd)

developing this program, may allow the release of low levels of constituents resulting in the need for various levels of remediation. Where we have 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. Sites currently undergoing remediation include the following:

Oak Creek North Landfill: Groundwater impairments at this landfill, located in the City of Oak Creek, Wisconsin, prompted us to investigate, during 1998, the condition of the existing cover and other conditions at the site. Surface water drainage improvements were effectively implemented at this site during 1999 and 2000. The approved remediation plan was coordinated with activities associated with the construction of the Oak Creek expansion. Currently there is a temporary cap installed, which is used as laydown area and parking. When construction activities are completed, a permanent cap will be installed.

South Oak Creek Landfill: Groundwater impairments near this landfill, located in the City of Oak Creek, Wisconsin, prompted us to begin investigation in 2009 for the source of impacts identified in monitoring wells on the site and the surrounding area. Preliminary results indicate that the groundwater impacts may be naturally occurring, or are from another source. Soils from construction of the Oak Creek expansion were added to the existing cover during 2005 and 2006 to increase the thickness of cover materials. A landfill closure application will be completed when the construction documentation report for activities associated with the Oak Creek expansion is submitted to the WDNR.

OTHER

Research and Development: We had immaterial research and development expenditures in the last three years, primarily for improvement of service and abatement of air and water pollution by our electric utility operations. Research and development activities include work done by employees, consultants and contractors, plus sponsorship of research by industry associations.

Employees: As of December 31, 2010, we had 4,128 total employees, of which 2,696 were represented under labor agreements with the following bargaining units:

	Number of Employees	Expiration Date of Current Labor Agreement
Local 2150 of International Brotherhood of Electrical Workers	1,868	August 15, 2012
Local 317 of International Union of Operating Engineers	539	March 31, 2011
Local 2006 Unit 5 of United Steel Workers	161	November 1, 2011
Local 510 of International Brotherhood of Electrical Workers	128	April 30, 2012
Total	<u>2,696</u>	

ITEM 1A. RISK FACTORS***Our business is significantly impacted by governmental regulation.***

We are subject to significant state, local and federal governmental regulation. We are subject to the regulation of the PSCW as to retail electric, gas and steam rates in the state of Wisconsin, standards of service, issuance of securities, short-term debt obligations, construction of certain new facilities, transactions with affiliates, billing practices and various other matters. In addition, we are subject to the regulation of the MPSC as to the various matters associated with retail electric service in the state of Michigan, except as to the issuance of securities in the ordinary course of business, construction of certain new facilities, levels of short-term debt obligations and advance approval of transactions with affiliates in the ordinary course of business. Further, our hydroelectric facilities are regulated by FERC, and FERC also regulates our wholesale power service practices, electric reliability requirements, and participation in the interstate natural gas pipeline capacity market. Our significant level of regulation imposes restrictions on our operations and causes us to incur substantial compliance costs.

We are obligated to comply in good faith with all applicable governmental rules and regulations. If it is determined that we failed to comply with any applicable rules or regulations, whether through new interpretations or applications of the regulations or otherwise, we may be liable for customer refunds, penalties and other amounts, which could materially and adversely affect our results of operations and financial condition.

We estimate that approximately 87% 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. All of our natural gas and steam revenues are regulated by the PSCW. Our ability to obtain rate adjustments in the future is dependent upon regulatory action, and there can be no assurance that we will be able to obtain rate adjustments in the future that will allow us to recover our costs and expenses and to maintain our current authorized rates of return.

We believe we have obtained the necessary permits, approvals and certificates for our existing operations and that our respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to us cannot be predicted. Changes in regulation, interpretations of regulations or the imposition of additional regulations could influence our operating environment and may result in substantial compliance costs.

Factors beyond our control could adversely affect project costs and completion of major construction projects.

We are in the process of constructing new renewable generation and adding environmental controls equipment to existing generating facilities. These types of large construction projects are subject to usual construction risks over which we will have limited or no control and which might adversely affect project costs and completion time. These risks include, but are not limited to, shortages of, the ability to obtain or the cost of labor or materials; the ability of the contractors to perform under their contracts; strikes; adverse weather conditions; the ability to obtain necessary operating permits in a timely manner; legal challenges; changes in applicable law or regulations; adverse interpretation or enforcement of permit conditions, laws and regulations by courts or the permitting agencies; other governmental actions; and events in the global economy.

If we are unable to complete the development or construction of a facility or decide to delay or cancel construction, we may not be able to recover our investment in the facility and may incur substantial cancellation payments under equipment and construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and/or higher than amounts approved by our regulators, and there is no guarantee that we will be allowed to recover these costs in rates. In addition, construction delays can result in the delay of revenues and, therefore, could affect our results of operations.

ITEM 1A. RISK FACTORS - (Cont'd)***We may face significant costs of compliance with existing and future environmental regulations.***

Our operations are subject to extensive environmental legislation and regulation by state and federal environmental agencies governing, among other things, air emissions such as Carbon Dioxide (CO₂), SO₂, NO_x, fine particulates and mercury; water discharges; and management of hazardous, toxic and solid wastes and substances. We incur significant expenditures in complying with these environmental requirements, including expenditures for the installation of pollution control equipment, environmental monitoring, emissions fees and permits at all of our facilities.

Existing environmental regulations may be revised or new laws or regulations may be adopted which could result in significant additional expenditures, operating restrictions on our facilities and increased compliance costs. The EPA has proposed a new rule, the Clean Air Transport Rule (CATR), to replace the Clean Air Interstate Rule (CAIR). We estimate the capital expenditures necessary to comply with the CATR and other new environmental regulations that are being promulgated at the federal and state level could be up to \$400 million above the expected cost of implementing the Consent Decree between us and the EPA. Some of these costs are included in the table under "Capital Expenditures" in the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations. In addition, the operation of emission control equipment and further regulations on our intake and discharge of water could increase our operating costs and could reduce the generating capacity of our power plants. In the event we are not able to recover all of our environmental expenditures from our customers in the future, our results of operations could be adversely affected.

Environmental legislation and regulation and the related compliance costs could affect future unit retirement and replacement decisions, and could result in some of our coal-fired generating units being retired or converted to an alternative type of fuel. Costs associated with these potential actions could affect our results of operations and financial condition.

Our electric and gas utility businesses are also subject to significant liabilities related to the investigation and remediation of environmental contamination at certain of our current and former facilities, and at third-party owned sites. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate.

We may also be subject to potential liability in connection with the environmental condition of the facilities that we have previously owned and operated, regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. If we fail (or failed) to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, even if caused by factors beyond our control, that failure or harm may result in the assessment of civil or criminal penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a significant adverse effect on our results of operations and financial condition.

In addition, any higher costs that are collected through rates could contribute to reduced demand for electricity, natural gas or steam, which could adversely impact our results of operations and financial condition.

We may face significant costs if coal combustion products are regulated as hazardous waste.

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. However, the EPA issued a draft rule for public comment proposing various scenarios for regulating coal combustion products including classifying coal combustion products as hazardous waste. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program.

ITEM 1A. RISK FACTORS - (Cont'd)

In addition, 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.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Federal and state legislative and regulatory proposals have been introduced to regulate the emission of greenhouse gases, particularly CO₂, and the President and his administration have made it clear that they are focused on reducing such emissions through legislation and/or regulation. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

We believe that future governmental legislation and/or regulation will require us either to limit greenhouse gas emissions from our operations or to purchase allowances for such emissions. However, we cannot currently predict with any certainty what form these future regulations will take, the stringency of the regulations or when they will become effective. We expect the U.S. Congress to continue consideration of legislation that would compel greenhouse gas emission reductions.

Legislation to regulate greenhouse gas emissions and establish renewable and efficiency standards has also been considered on the state level. The state of Michigan has enacted legislation that calls for the implementation of a renewable portfolio standard by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. The state of Wisconsin has adopted its own renewable portfolio standard and energy optimization targets. During its 2010 legislative session, the Wisconsin legislature considered, but ultimately did not pass, a proposal to increase Wisconsin's renewable portfolio standard and energy optimization targets. There is no guarantee the legislature will not consider similar legislation in the future.

In addition to these federal and state legislative efforts, the EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the Clean Air Act (CAA). In December 2009, the EPA issued its endangerment finding related to greenhouse gas emissions, which set in motion a regulatory process that is leading to regulation of greenhouse gas emissions from stationary sources, including electric generating units. In March 2010, the EPA finalized its determination of when the CAA's permitting requirements for emissions from facilities would apply to greenhouse gas emissions. The regulation of stationary sources will occur in multiple steps in the coming years, beginning with the first step that became effective January 2, 2011. This initial step covers sources that are already subject to EPA regulations for pollutants other than greenhouse gas. In July 2011, the second step is scheduled to become effective, covering new construction projects and modifications at existing power plants. Additionally, in December 2010, the EPA reached an agreement with several states and environmental groups to propose and finalize rules regulating greenhouse gas emissions from certain new or modified coal-fired power plants and guidelines addressing greenhouse gas emissions from certain existing power plants by May 26, 2012. Regulation of greenhouse gas emissions from power plants will impact our ability to do maintenance or modify our existing facilities, and permit new facilities. Several parties have filed for judicial review of some of the EPA's new greenhouse gas rules. In December 2010, the federal court denied a motion to stay the greenhouse gas rules pending judicial review, so the rules will continue in effect unless overturned by the court. Depending on the extent of rate recovery and other factors, these rules could have a material adverse impact on our financial condition.

Some states and environmental groups are also bringing lawsuits against electric utilities and others to force reductions in greenhouse gas emissions. To date, three separate lawsuits are pending in the federal courts. In two of these cases, the federal appellate courts have found in favor of the plaintiffs, making it easier for lawsuits based upon the alleged public nuisance of climate change to move forward. These cases essentially hold that plaintiffs have standing to file suit against electric power corporations for their contribution to the alleged public nuisance of climate change, and that the court's jurisdiction over such lawsuit is not barred by the political question doctrine. One of these lawsuits (*Comer v. Murphy Oil USA*), was vacated by the U.S. Court of Appeals for the Fifth Circuit on procedural grounds. In the second lawsuit (*Connecticut v. American Electric Power Co.*), the defendants petitioned the United States Supreme Court to review the decision of the U.S. Court of Appeals for the Second Circuit, which it agreed to do.

ITEM 1A. RISK FACTORS - (Cont'd)

There is no guarantee that we will be allowed to fully recover costs incurred to comply with any future legislation, regulation or order that requires a reduction in greenhouse gas emissions or that cost recovery will not be delayed or otherwise conditioned. Any cap-and-trade or greenhouse gas tax program that may be adopted, either at the federal or state level, or other legislation, regulation or order designed to reduce greenhouse gas emissions could have a material adverse impact on our electric generation and natural gas distribution operations. Such regulation could make some of our electric generating units uneconomic to maintain or operate, and could affect our future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

We continue to monitor the legislative, regulatory and legal developments in this area. Although we expect the regulation of greenhouse gas emissions to have a material impact on our operations and rates, we believe it is premature to attempt to quantify the possible costs of the impacts.

Our business is dependent on our ability to successfully access capital markets.

We rely on access to short-term and long-term capital markets to support our capital expenditures and other capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities, preferred stock and equity contributions from our parent, Wisconsin Energy. Successful implementation of our long-term business strategies is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, under competitive terms and rates. If our access to any of these markets were limited, or our cost of capital significantly increased due to a rating downgrade, prevailing market conditions, negative view of the utility industry, failures of financial institutions or other factors, our results of operations and financial condition could be materially and adversely affected.

A downgrade in our credit ratings could negatively affect our ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact our credit ratings, including, without limitation, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We could experience a downgrade in our ratings if the rating agencies determine that the level of business or financial risk of the industry or the Company has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings. If we are downgraded by the rating agencies, our borrowing costs could increase, funding sources could decrease and, for any downgrade to below investment grade, collateral requirements may be triggered in several contracts.

The use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures and forwards to manage commodity price exposure. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, although our hedging programs must be approved by the PSCW, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

Acts of terrorism could materially and adversely affect our financial condition and results of operations.

Our electric generation and gas transportation facilities, including the facilities of third parties on which we rely, could be targets of terrorist activities, including cyber terrorism. A terrorist attack on our facilities (or those of third parties) could result in a full or partial disruption of our ability to generate, transmit, transport, purchase or distribute electricity or natural gas or cause environmental repercussions. Any

ITEM 1A. RISK FACTORS - (Cont'd)

operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations and financial condition.

Energy sales are impacted by seasonal factors and varying weather conditions from year-to-year.

Our electric and gas utility businesses are generally seasonal businesses. Demand for electricity is greater in the summer and winter months associated with cooling and heating. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results in the future may fluctuate substantially on a seasonal basis. In addition, we have historically had lower revenues and net income when weather conditions are milder. Our rates in Wisconsin are set by the PSCW based on estimated temperatures which approximate 20-year averages. Mild temperatures during the summer cooling season and during the winter heating season will negatively impact the results of operations and cash flows of our electric utility business. In addition, mild temperatures during the winter heating season negatively impact the results of operations and cash flows of our gas utility business.

Our revenues could be negatively impacted by competitive activity in the wholesale electricity markets.

FERC rules related to transmission are designed to facilitate competition in the wholesale electricity markets among regulated utilities, non-utility generators, wholesale power marketers and brokers by providing greater flexibility and more choices to wholesale customers, including initiatives designed to encourage the integration of renewable sources of supply. We currently cannot predict the impact of these developments or the effect of changes in levels of wholesale supply and demand, which are driven by factors beyond our control.

An increase in natural gas costs could negatively impact our electric and gas utility operations.

We burn natural gas in several of our peaking power plants and in PWGS 1 and PWGS 2, and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. In addition, higher natural gas costs also can have the effect of increasing demand for other sources of fuel thereby increasing the costs of those fuels as well. For Wisconsin customers, Wisconsin Electric bears the risk for the recovery of fuel and purchased power costs within a symmetrical two percent fuel tolerance band compared to the forecast of fuel and purchased power costs established in its rate structure. Our gas distribution business receives dollar for dollar recovery of the cost of natural gas, subject to tolerance bands and prudence review. However, increased natural gas costs increase the risk that customers will switch to alternative sources of fuel or reduce their usage, which could reduce future gas margins. In addition, an increase in natural gas costs combined with slower economic conditions could also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Additionally, high natural gas costs increase our working capital requirements.

We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

We are dependent on coal for much of our electric generating capacity. Although we currently have an adequate supply of coal at our coal-fired facilities, there can be no assurance that we will continue to have an adequate supply of coal in the future. While we have coal supply and transportation contracts in place, there can be no assurance that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. In addition, suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. If we significantly reduce our inventory of coal and are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices, or we may be forced to reduce generation at our coal units and replace this lost generation from higher cost generating resources or through additional power purchases in the MISO Energy Markets.

ITEM 1A. RISK FACTORS - (Cont'd)***Our financial performance may be adversely affected if we are unable to successfully operate our facilities.***

Our financial performance depends on the successful operation of our electric generating and gas distribution facilities. Operation of these facilities involves many risks, including: operator error and breakdown or failure of equipment processes; fuel supply interruptions; labor disputes; operating limitations that may be imposed by environmental or other regulatory requirements; or catastrophic events such as fires, earthquakes, explosions, floods or other similar occurrences. Unplanned outages can result in additional maintenance expenses as well as incremental replacement power costs.

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

Our cost of providing defined benefit pension plans is dependent upon a number of factors including actual plan experience and assumptions concerning the future, such as earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and our required or voluntary contributions to be made to the plans. Changes made to the plans may also impact current and future pension costs. Depending upon the growth rate of the pension investments over time and other factors impacting our costs as listed above, we may be required to contribute significant additional amounts in the future to fund our plans. These additional funding obligations could have a material adverse impact on our cash flows, financial condition or results of operations.

We are exposed to risks related to general economic conditions in our service territories.

Our electric and gas utility businesses are impacted by economic cycles and the competitiveness of the customers we serve. As the demand for products produced in our service area declines, we ordinarily experience reduced demand for electricity and/or natural gas. During 2010 our service territory experienced growth but future growth could be impacted by the overall economy in our service territories. If the economic conditions in our service territories and/or demand for products produced in our service area does not continue to improve or declines again, we could experience a reduction in demand for electricity and/or natural gas that could result in decreased earnings and cash flow. We would also expect our collections of accounts receivable to be adversely impacted.

Customer growth in our service areas affects our results of operations.

Our results of operations are affected by customer growth in our service areas. Customer growth can be affected by population growth as well as economic factors in Wisconsin and the Upper Peninsula of Michigan, including job and income growth. Customer growth directly influences the demand for electricity and gas, and the need for additional power generation and generating facilities. Population declines and/or business closings in our service territories or slower than anticipated customer growth has had, to a limited extent, and could continue to have, a material adverse impact on our cash flow, financial condition or results of operations.

Failure to attract and retain an appropriately qualified workforce could adversely impact our results of operations.

Events such as an aging workforce without appropriate replacements may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

ITEM 1A. RISK FACTORS - (Cont'd)***Governmental agencies could modify our permits, authorizations or licenses.***

We are required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency.

Also, if we are unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if we are unable to recover any increased costs of complying with additional license requirements or any other associated costs in our rates in a timely manner, our results of operations and financial condition could be materially and adversely affected.

We could be subject to higher costs and penalties as a result of mandatory reliability standards.

We are subject to mandatory reliability standards established by the North American Electric Reliability Corporation. Compliance with the mandatory reliability standards could subject us to higher operating costs. If we are found to be in noncompliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Restructuring in the regulated energy industry could have a negative impact on our business.

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us. It is uncertain when retail access might be implemented in Wisconsin; however, Michigan has adopted retail choice which allows customers to choose their own electric generation supplier. Although competition and customer switching to alternative suppliers in our service territories in Michigan has been limited, the additional competitive pressures resulting from retail access could lead to a loss of customers and our incurring stranded costs.

FERC continues to support the existing RTOs that affect the structure of the wholesale market within those RTOs. In connection with its status as a FERC approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. The MISO Energy Markets rules require that all market participants submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes a Locational Marginal Price (LMP) that reflects the market price for energy. As a participant in the MISO Energy Markets, we are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining stability of the transmission system. MISO also implemented an Ancillary Services Market for operating reserves that was simultaneously co-optimized with its existing energy markets.

These market designs have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the market and the costs associated with estimated payment settlements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own our principal properties outright, except that the major portion of our electric utility distribution lines, steam utility distribution mains and gas utility distribution mains and services are located, for the most part, on or under streets and highways and on land owned by others and are generally subject to granted easements, consents or permits. In addition, we lease the PTF generating units.

As of December 31, 2010, we owned, or leased from We Power, the following generating stations:

Name	Fuel	No. of Generating Units	Dependable Capability in MW (a)
Coal-Fired Plants			
South Oak Creek	Coal	4	1,139
Oak Creek Expansion (b)	Coal	1	515
Presque Isle	Coal	5	431
Pleasant Prairie	Coal	2	1,218
Valley	Coal	2	227
Edgewater 5 (c)	Coal	1	105
Milwaukee County	Coal	3	11
Total Coal-Fired Plants		18	3,646
Hydro Plants (13 in number)		33	57
Port Washington Generating Station	Gas	2	1,090
Germantown Combustion Turbines	Gas/Oil	5	345
Concord Combustion Turbines	Gas/Oil	4	400
Paris Combustion Turbines	Gas/Oil	4	400
Other Combustion Turbines & Diesel	Gas/Oil	2	5
Byron Wind Turbines (d)	Wind	2	-
Blue Sky Green Field (e)	Wind	88	29
Total System		158	5,972

- (a) Dependable capability is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. We are a summer peaking electric utility. The values are established by tests and may change slightly from year to year.
- (b) OC 2 was placed in service on January 12, 2011 and is therefore not included in the table above. See Note S -- Subsequent Events for additional information. Our share of the dependable capability of this unit is estimated to be 515 MW.
- (c) We have a 25% interest in Edgewater Generating Unit 5, which is operated by WPL, an unaffiliated utility. During the fourth quarter of 2009, we reached a contingent agreement with WPL to sell our interest in this unit. For further information, see Note D -- Divestitures.
- (d) The Byron Wind Turbines are able to generate up to 1.2 MW of electricity; however, due to the intermittent characteristics of wind power, their dependable capability is less than 1 MW.
- (e) Blue Sky Green Field is able to generate up to approximately 145 MW of electricity; however, due to the intermittent characteristics of wind power, its dependable capability is approximately 29 MW.

As of December 31, 2010, our electric utility operated approximately 21,679 pole-miles of overhead distribution lines and 23,664 miles of underground distribution cable, as well as approximately 353 distribution substations and 285,573 line transformers.

As of December 31, 2010, our gas distribution system included approximately 9,401 miles of distribution mains connected at 26 gate stations to the pipeline transmission systems of ANR Pipeline Company, Guardian, Natural Gas Pipeline Company of America, Northern Natural Pipeline Company and Great Lakes Transmission Company. We have a liquefied natural gas storage plant that converts and stores in

ITEM 2. PROPERTIES - (Cont'd)

liquefied form natural gas received during periods of low consumption. The liquefied natural gas storage plant has a send-out capability of 70,000 Dth per day. Our gas distribution system consists almost entirely of plastic and coated steel pipe.

We also own office buildings, gas regulating and metering stations and major service centers, including garage and warehouse facilities, in certain communities we serve. Where distribution lines and services and gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

As of December 31, 2010, the combined steam systems supplied by the Valley and Milwaukee County Power Plants consisted of approximately 43 miles of both high pressure and low pressure steam piping, nine miles of walkable tunnels and other pressure regulating equipment.

ITEM 3. LEGAL PROCEEDINGS

In addition to those legal proceedings discussed below, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these other legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material adverse effect on our financial statements.

ENVIRONMENTAL MATTERS

We are subject to federal, state and certain local laws and regulations governing the environmental aspects of our operations. Management believes that our existing facilities are in material compliance with applicable environmental requirements.

Solvay Coke and Gas Site: We have been identified as a potentially responsible party at the Solvay Coke and Gas Site located in Milwaukee, Wisconsin. A predecessor company owned a parcel of property that is within the property boundaries of the site. In 2007, we and several other parties entered into an Administrative Settlement Agreement and Order with the EPA to perform additional investigation and assessment and reimburse the EPA's oversight costs. Under the Administrative Settlement Agreement, we do not admit to any liability for the site, waive any liability defenses, or commit to perform future site remedial activities at this time. Our share of the costs to perform the required work and reimburse the EPA's oversight costs, as well as potential future remediation cost estimates and reserves, are included in the estimated manufactured gas plant values reported in Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Edgewater Generating Unit 5: In December 2009, the EPA issued a Notice of Violation (NOV) concerning several coal-fired power plants owned and operated by WPL, including Edgewater Generating Unit 5, of which we own 25%. Due to that ownership interest, we were named in the NOV. The NOV alleges that certain maintenance projects at WPL's units, including Edgewater 5, were undertaken without obtaining air permits required by the CAA. We, along with WPL, who is the primary owner and operator of the plants, and the co-owners of the other plants identified in the NOV, are discussing resolution of this NOV with the EPA. At this time, we cannot predict the outcome of this matter. In September 2010, the Sierra Club filed a complaint against WPL generally alleging air permitting and opacity violations at the Edgewater Generating Station. We are not a named party to this litigation. At this time, we cannot predict the outcome of this matter.

See Environmental Compliance in Item 1 and Environmental Matters, Manufactured Gas Plant Sites, Coal Combustion Product Landfill Sites and EPA - Consent Decree in Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements which are incorporated by reference herein, for a discussion of matters related to certain solid waste and coal combustion product landfills, manufactured gas plant sites and air quality.

ITEM 3. LEGAL PROCEEDINGS - (Cont'd)**UTILITY RATE MATTERS**

See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7 for information concerning rate matters in the jurisdictions where we do business.

OTHER MATTERS

Used Nuclear Fuel Storage and Removal: See Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations in Item 7 for information concerning the United States Department of Energy's (DOE) breach of contract with us that required the DOE to begin permanently removing used nuclear fuel from Point Beach by January 31, 1998.

Stray Voltage: In recent years, several actions by dairy farmers have been commenced or claims made against us for loss of milk production and other damages to livestock allegedly caused by stray voltage resulting from the operation of our electrical system. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 7.

Cash Balance Pension Plan: See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 7 for information regarding a lawsuit filed against the Plan.

For information regarding additional legal matters, see Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 7. For information concerning Wisconsin Energy's PTF strategy, see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future.

ITEM 4. [Removed and Reserved]**EXECUTIVE OFFICERS OF THE REGISTRANT**

The names, ages at December 31, 2010 and positions of our executive officers are listed below along with their business experience during the past five years. All officers are appointed until they resign, die or are removed pursuant to the Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected.

Gale E. Klappa. Age 60.

- Wisconsin Energy -- Chairman of the Board and Chief Executive Officer since May 2004. President since April 2003.
- Wisconsin Electric -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Wisconsin Gas -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Director of Joy Global, Inc. and Badger Meter, Inc.
- Director of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas since 2003.

Charles R. Cole. Age 64.

- Wisconsin Electric -- Senior Vice President since 2001.
- Wisconsin Gas -- Senior Vice President since July 2004.

EXECUTIVE OFFICERS OF THE REGISTRANT - (Cont'd)**Stephen P. Dickson.** Age 50.

- Wisconsin Energy -- Vice President since 2005. Controller since 2000.
- Wisconsin Electric -- Vice President since 2005. Controller since 2000.
- Wisconsin Gas -- Vice President since 2005. Controller since 1998.

James C. Fleming. Age 65.

- Wisconsin Energy -- General Counsel since March 2006. Executive Vice President since January 2006.
- Wisconsin Electric -- General Counsel since March 2006. Executive Vice President since January 2006.
- Wisconsin Gas -- General Counsel since March 2006. Executive Vice President since January 2006.
- Southern Company Services, Inc. -- Vice President and Associate General Counsel from 1998 to December 2005. Southern Company Services is an affiliate of The Southern Company, a public utility holding company serving the southeastern United States.

Frederick D. Kuester. Age 60.

- Wisconsin Energy -- Executive Vice President since May 2004.
- Wisconsin Electric -- Executive Vice President since May 2004. Chief Operating Officer since October 2003.
- Wisconsin Gas -- Executive Vice President since May 2004.

Mirant Corporation, of which Mr. Kuester was Senior Vice President - International from 2001 to October 2003 and Chief Executive Officer of Mirant Asia-Pacific Limited from 1999 to October 2003, and certain of its subsidiaries voluntarily filed for bankruptcy in July 2003. Other than certain Canadian subsidiaries, none of Mirant's international subsidiaries filed for bankruptcy.

Allen L. Leverett. Age 44.

- Wisconsin Energy -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.
- Wisconsin Electric -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.
- Wisconsin Gas -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.

Kristine A. Rappé. Age 54.

- Wisconsin Energy -- Senior Vice President and Chief Administrative Officer since May 2004.
- Wisconsin Electric -- Senior Vice President and Chief Administrative Officer since May 2004.
- Wisconsin Gas -- Senior Vice President and Chief Administrative Officer since May 2004.

Certain executive officers also hold offices in Wisconsin Energy's non-utility subsidiaries and our non-utility subsidiary.

PART II**ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES****DIVIDENDS AND COMMON STOCK PRICES**

Dividends declared on our common stock during the two most recent fiscal years are set forth below. Dividends were paid entirely in cash. Dividends were paid to our sole common stockholder, Wisconsin Energy Corporation. There is no established public trading market for our common stock.

<u>Quarter</u>	<u>2010</u>	<u>2009</u>
	(Millions of Dollars)	
First	\$44.9	\$44.9
Second	44.9	44.9
Third	44.9	44.9
Fourth	44.9	44.9
Total	<u>\$179.6</u>	<u>\$179.6</u>

Subject to any regulatory restriction 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, our earnings, financial condition and other requirements.

Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. Under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. For additional information regarding restrictions on our ability to pay dividends, see Note H -- Common Equity in the Notes to Consolidated Financial Statements in Item 8.

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

<u>Financial</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>	<u>2006</u>
Year Ended December 31					
Earnings available for common stockholder (Millions)	\$ 314.2	\$ 287.4	\$ 280.1	\$ 287.7	\$ 275.6
Operating revenues (Millions)					
Electric	\$ 2,936.3	\$ 2,685.0	\$ 2,660.6	\$ 2,674.6	\$ 2,499.5
Gas	481.6	564.2	709.2	611.9	590.0
Steam	38.8	39.1	40.3	35.1	27.2
Total operating revenues	<u>\$ 3,456.7</u>	<u>\$ 3,288.3</u>	<u>\$ 3,410.1</u>	<u>\$ 3,321.6</u>	<u>\$ 3,116.7</u>
At December 31 (Millions)					
Total assets	\$ 10,170.7	\$ 8,871.2	\$ 8,775.4	\$ 8,312.8	\$ 8,257.8
Long-term debt and capital lease obligations (including current maturities)	\$ 4,053.5	\$ 3,092.8	\$ 2,886.4	\$ 1,990.4	\$ 2,152.1

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars) (a)			
	March		June	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
<u>Three Months Ended</u>				
Total operating revenues	\$ 933.9	\$ 988.4	\$ 777.6	\$ 723.7
Operating income	\$ 130.8	\$ 158.1	\$ 96.2	\$ 87.2
Earnings available for common stockholder	\$ 79.1	\$ 98.5	\$ 61.1	\$ 51.2
	September		December	
<u>Three Months Ended</u>	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Total operating revenues	\$ 883.2	\$ 738.3	\$ 862.0	\$ 837.9
Operating income	\$ 139.6	\$ 83.4	\$ 122.6	\$ 140.2
Earnings available for common stockholder	\$ 89.3	\$ 52.4	\$ 84.7	\$ 85.3

(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.

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

CORPORATE DEVELOPMENTS

INTRODUCTION

Wisconsin Electric Power Company, a wholly-owned subsidiary of Wisconsin Energy, is engaged primarily in the business of generating and distributing electricity in Wisconsin and the Upper Peninsula of Michigan, and distributing natural gas in Wisconsin. Unless qualified by their context when used in this document, the terms Wisconsin Electric, the Company, our, us or we refer to Wisconsin Electric Power Company and its subsidiary, Bostco.

Wisconsin Energy is also the parent company of Wisconsin Gas, a natural gas distribution utility, which serves customers throughout Wisconsin; and We Power, an unregulated company that was formed in 2001 to design, construct, own and lease to us the new generating capacity included in Wisconsin Energy's PTF strategy, which is described further in this report. We have combined common functions with Wisconsin Gas and operate under the trade name of "We Energies."

CORPORATE STRATEGY

Business Opportunities

We have two primary investment opportunities and earnings streams: our regulated utility business and our investment in ATC.

Our regulated utility business consists of electric generation assets and the electric and gas distribution assets that serve our electric and gas customers. During 2010, our regulated utility earned \$489.2 million of operating income. Over the next three years, we expect to invest approximately \$1.8 billion in this business to construct renewable energy generation and environmental control equipment and to update the electric and gas distribution infrastructure.

We have a \$290.6 million investment in ATC, which represents a 23.0% ownership interest. Our 2010 pre-tax earnings totaled \$52.7 million and we received \$43.3 million in dividends from ATC. Over the next three years, we expect to invest approximately \$17 million in ATC as it continues to upgrade the transmission infrastructure within Wisconsin.

RESULTS OF OPERATIONS

EARNINGS

2010 vs. 2009: Earnings increased to \$314.2 million in 2010 compared with \$287.4 million in 2009. Operating income increased \$20.3 million between the comparative periods. 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. During 2010, we experienced unfavorable fuel recoveries of approximately \$44 million. During 2009, we experienced favorable fuel recoveries of approximately \$19 million.

2009 vs. 2008: Earnings increased to \$287.4 million in 2009 compared with \$280.1 million in 2008. Operating income decreased \$13.0 million between the comparative periods. The most significant factors that impacted operating income during 2009 were less favorable weather during the spring and summer months and a decline in economic conditions throughout 2009, both of which decreased electric sales. However, we experienced a decrease in fuel and purchased power costs largely due to lower MWh sales and a decrease in operating and maintenance expense during 2009 as compared to 2008.

**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS - (Cont'd)**

The following table summarizes our consolidated earnings during 2010, 2009 and 2008:

	<u>2010</u>	<u>2009</u>	<u>2008</u>
		(Millions of Dollars)	
Utility Gross Margin			
Electric (See below)	\$1,844.8	\$1,632.9	\$1,431.5
Gas (See below)	165.6	174.5	182.8
Steam	25.6	26.7	27.1
Total Gross Margin	<u>2,036.0</u>	<u>1,834.1</u>	<u>1,641.4</u>
Other Operating Expenses			
Other operation and maintenance	1,432.5	1,231.7	1,295.2
Depreciation and amortization	216.2	265.1	256.0
Property and revenue taxes	96.5	99.1	96.4
Amortization of gain	(198.4)	(230.7)	(488.1)
Operating Income	<u>489.2</u>	<u>468.9</u>	<u>481.9</u>
Equity in Earnings of Transmission Affiliate	52.7	51.9	45.4
Other Income and Deductions, net	39.8	25.8	9.9
Interest Expense, net	<u>101.5</u>	<u>100.3</u>	<u>86.6</u>
Income Before Income Taxes	480.2	446.3	450.6
Income Taxes	164.8	157.7	169.3
Preferred Stock Dividend Requirement	1.2	1.2	1.2
Earnings Available for Common Stockholder	<u><u>\$314.2</u></u>	<u><u>\$287.4</u></u>	<u><u>\$280.1</u></u>

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2010 with similar information for 2009 and 2008, including a summary of electric operating revenues and electric sales by customer class:

Electric Utility Operations	Electric Revenues and Gross Margin			Electric MWh Sales		
	2010	2009	2008	2010	2009	2008
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	\$1,114.3	\$977.6	\$962.5	8,426.3	7,949.3	8,277.1
Small Commercial/Industrial	922.2	860.3	869.7	8,823.3	8,571.6	9,023.7
Large Commercial/Industrial	677.1	599.4	646.3	9,961.5	9,140.3	10,691.7
Other - Retail	21.9	21.2	20.8	155.3	156.5	161.5
Total Retail	2,735.5	2,458.5	2,499.3	27,366.4	25,817.7	28,154.0
Wholesale - Other	134.6	116.7	77.7	2,004.6	1,529.4	2,620.7
Resale - Utilities	40.4	47.5	37.7	1,103.8	1,548.9	881.0
Other Operating Revenues	25.8	62.3	45.9	-	-	-
Total	2,936.3	2,685.0	2,660.6	30,474.8	28,896.0	31,655.7
Fuel and Purchased Power						
Fuel	570.5	518.3	570.6			
Purchased Power	521.0	533.8	658.5			
Total Fuel and Purchased Power	1,091.5	1,052.1	1,229.1			
Total Electric Gross Margin	\$1,844.8	\$1,632.9	\$1,431.5			
Weather -- Degree Days (a)						
Heating (6,612 Normal)				6,183	6,825	7,073
Cooling (698 Normal)				944	475	593

(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

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 -- 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. For information on the bill credits, see Amortization of Gain below.

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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

compared to 2009. The \$36.5 million decline in Other Operating Revenues primarily relates to regulatory amortizations during 2010 as compared to 2009.

We currently estimate that 2011 electric revenues will increase because of the completion of the Point Beach bill credits and an increase in revenues related to increased fuel costs. However, we would expect residential and small commercial and industrial sales to decrease if we experience normal weather.

2009 vs. 2008: Our electric utility operating revenues increased by \$24.4 million, or 0.9%, when compared to 2008. The most significant factors that caused a change in revenues were:

- 2009 pricing increases totaling approximately \$109.9 million reflecting the reduction of Point Beach credits to retail customers.
- A one-time FERC-approved refund to our wholesale customers in 2008 associated with their share of the gain on the sale of Point Beach that reduced 2008 wholesale revenues by \$62.5 million.
- Net pricing increases totaling approximately \$20.4 million related to Wisconsin and Michigan rate orders.
- Unfavorable weather that reduced electric revenues by an estimated \$35.3 million as compared to 2008.
- A slowdown in the economy that reduced commercial and industrial sales by an estimated \$129.0 million and wholesale sales by an estimated \$30.9 million.

Our total electric sales volumes decreased by approximately 8.7% as compared to 2008 due almost exclusively to a continued decline in economic conditions, which primarily affected our commercial and industrial sales, and milder weather, which primarily affected our residential sales. Total retail sales volumes declined approximately 8.3%. Of the 8.3% decline in retail sales volumes, approximately 7.1% relates to sales volumes at our small and large commercial and industrial customers. As measured by cooling degree days, 2009 was 19.9% cooler than 2008 and 31.9% cooler than normal. The \$16.4 million increase in Other Operating Revenues primarily relates to regulatory amortizations during 2009 as compared to 2008.

Electric Fuel and Purchased Power Expenses

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 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.

We expect electric fuel and purchased power expenses to increase in 2011 because of changes in the price of natural gas and in the cost of coal and related transportation prices.

2009 vs. 2008: Our electric fuel and purchased power costs decreased by \$177.0 million, or approximately 14.4%, when compared to 2008. This decline was primarily caused by lower MWh sales and lower natural gas and purchased power prices, partially offset by higher coal and related transportation costs. Approximately \$41.2 million of this decrease related to the one-time amortization of deferred fuel costs recorded in the first quarter of 2008 pursuant to the January 2008 PSCW rate order. Adjusted for the one-time amortization, our electric fuel and purchased power costs decreased by \$135.8 million, or 11.0%.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 2010, 2009 and 2008:

Gas Utility Operations	2010	2009	2008
	(Millions of Dollars)		
Operating Revenues	\$481.6	\$564.2	\$709.2
Cost of Gas Sold	316.0	389.7	526.4
Gross Margin	\$165.6	\$174.5	\$182.8

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under our GCRM. The following table compares our gas utility gross margin and therm deliveries by customer class during 2010, 2009 and 2008:

Gas Utility Operations	Gross Margin			Therm Deliveries		
	2010	2009	2008	2010	2009	2008
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	\$111.2	\$117.3	\$120.5	321.8	349.4	364.7
Commercial/Industrial	35.8	40.2	41.9	184.5	208.8	216.2
Interruptible	0.6	0.6	0.7	5.5	5.9	6.9
Total Retail	147.6	158.1	163.1	511.8	564.1	587.8
Transported Gas	15.5	14.3	15.8	300.8	298.4	313.3
Other	2.5	2.1	3.9	-	-	-
Total	\$165.6	\$174.5	\$182.8	812.6	862.5	901.1

Weather -- Degree Days (a)

Heating (6,612 Normal)	6,183	6,825	7,073
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(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

2010 vs. 2009: Our gas margin decreased by \$8.9 million, or approximately 5.1%, 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.

2009 vs. 2008: Our gas margin decreased by \$8.3 million, or approximately 4.5%, when compared to 2008. We estimate that milder winter weather and a decline in economic conditions caused our margin to decrease by approximately \$5.4 million during 2009 as compared to 2008. As measured by heating degree days, 2009 was 3.5% warmer than 2008, but 2.8% colder than normal.

Other Operation and Maintenance Expense

2010 vs. 2009: Our other operation and maintenance expense increased by \$200.8 million, or approximately 16.3%, when compared to 2009. The 2010 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 \$72.6 million higher in 2010 as compared to 2009. In addition, operation and maintenance expenses at our power plants increased approximately \$63.7 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 \$20.7 million related to increased reliability

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

maintenance in our distribution system in 2010 and responding to damage caused by a larger number of summer storms compared to 2009.

Our utility operation and maintenance expenses are influenced by labor costs, employee benefit costs, plant outages and amortization of regulatory assets. We expect our 2011 other operation and maintenance expenses to increase slightly because of inflation related items.

2009 vs. 2008: Our other operation and maintenance expense decreased by \$63.5 million, or approximately 4.9%, when compared to 2008. The largest factor for this decrease relates to a \$43.8 million one-time amortization of deferred bad debt costs in 2008 pursuant to the January 2008 PSCW rate order. The January 2008 PSCW rate order, which was in effect for all of 2009, allowed for pricing increases related to transmission costs, PTF lease costs and the amortization of other deferred costs. We estimate that these items were approximately \$16.4 million higher in 2009 as compared to 2008. The remaining decrease is primarily related to reduced operating and maintenance expenses at our power plants and electric distribution system.

Depreciation and Amortization Expense

2010 vs. 2009: Depreciation and Amortization expense decreased by \$48.9 million, or approximately 18.4%, 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.

We expect depreciation and amortization expense to increase in 2011 as a result of an overall increase in utility plant in service.

2009 vs. 2008: Depreciation and amortization expense increased by \$9.1 million, or approximately 3.6%, when compared to 2008. This increase was primarily the result of higher depreciation related to new capital projects placed in service, including the Blue Sky Green Field wind project, which was placed in service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements 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 are being returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it is being amortized to the income statement as we issue bill credits or make refunds to our customers. When the bill credits and refunds are issued to customers, we transfer cash from the restricted accounts to the unrestricted accounts, adjusted for taxes.

During 2010, 2009 and 2008, the Amortization of Gain was as follows:

	2010	2009	2008
	(Millions of Dollars)		
Bill Credits - Retail	\$198.4	\$230.7	\$340.6
One-Time FERC Refund	-	-	62.5
One-Time Amortization to Offset Regulatory Asset	-	-	85.0
Total Amortization of Gain	<u>\$198.4</u>	<u>\$230.7</u>	<u>\$488.1</u>

All bill credits associated with the sale of Point Beach have been applied to customers' bills as of December 31, 2010.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Other Income and Deductions, net

Other Income and Deductions, net	2010	2009	2008
	(Millions of Dollars)		
AFUDC - Equity	\$32.4	\$15.9	\$7.5
Gain on Property Sales	4.5	1.7	2.3
Other, net	2.9	8.2	0.1
Total Other Income and Deductions, net	\$39.8	\$25.8	\$9.9

2010 vs. 2009: Other income and deductions, net increased by approximately \$14.0 million, or 54.3%, when compared to 2009. This increase primarily relates to increased AFUDC - Equity related to the construction of the Oak Creek Air Quality Control System (AQCS) project.

During 2011, we expect to see an increase in AFUDC - Equity with the continued construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

2009 vs. 2008: Other income and deductions, net increased by \$15.9 million when compared to 2008 primarily due to higher interest income and an increase in AFUDC - Equity related to the construction of the Oak Creek AQCS project.

Interest Expense, net

Interest Expense, net	2010	2009	2008
	(Millions of Dollars)		
Gross Interest Costs	\$115.0	\$106.9	\$89.6
Less: Capitalized Interest	13.5	6.6	3.0
Interest Expense, net	\$101.5	\$100.3	\$86.6

2010 vs. 2009: Our gross interest costs increased by \$8.1 million, or 7.6%, during 2010, primarily because of higher long-term debt balances compared to 2009. Our capitalized interest increased by \$6.9 million primarily because of increased capital expenditures related to our Oak Creek AQCS project. As a result, our net interest expense increased by \$1.2 million, or 1.2%, as compared to 2009.

During 2011, we expect gross interest expense to increase due to increased debt levels to fund our planned construction activity. We expect our capitalized interest to increase slightly due to increased capital expenditures related to our Oak Creek AQCS project and Glacier Hills Wind Park. As a result, we expect our net interest expense to increase slightly in 2011.

2009 vs. 2008: Our gross interest costs increased by \$17.3 million, or 19.3%, when compared to 2008, primarily due to higher debt balances to fund our planned construction activity, partially offset by lower short-term interest rates. Our capitalized interest increased by \$3.6 million due to increased capital expenditures in 2009 related to our Oak Creek AQCS project. As a result, our net interest expense increased by \$13.7 million, or 15.8%, as compared to 2008.

Income Taxes

2010 vs. 2009: Our effective income tax rate was 34.3% in 2010 compared with 35.3% in 2009. This reduction in our effective tax rate was primarily the result of increased AFUDC - Equity and increased production activities tax deductions. For further information regarding income taxes, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2011 annual effective tax rate to range between 32.0% and 33.0%.

2009 vs. 2008: Our effective income tax rate was 35.3% in 2009 compared with 37.6% in 2008. This reduction in our effective tax rate was primarily the result of tax credits associated with wind production.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2010, 2009 and 2008:

	<u>2010</u>	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)		
Cash Provided by (Used in)			
Operating Activities	\$425.2	\$226.6	\$362.9
Investing Activities	(\$470.8)	(\$333.6)	(\$212.7)
Financing Activities	\$50.6	\$96.9	(\$143.8)

Operating Activities

2010 vs. 2009: Cash provided by operating activities was \$425.2 million during 2010, which was an increase of \$198.6 million over 2009. This increase is primarily related to a \$283.8 million contribution to Wisconsin Energy's 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.

2009 vs. 2008: Cash provided by operating activities was \$226.6 million during 2009, which was \$136.3 million lower than 2008. Although we experienced an increase in net income and depreciation during 2009, our operating cash flows declined because of large contributions to Wisconsin Energy's qualified benefit plans. During 2009, we contributed \$283.8 million to Wisconsin Energy's qualified benefit plans compared to \$37.9 million during 2008.

Investing Activities

2010 vs. 2009: Cash used in investing activities was \$470.8 million during 2010, which was \$137.2 million higher than the same period in 2009. This increase in cash used in investing activities primarily reflects an increase in capital expenditures of \$136.2 million related to our Glacier Hills Wind Park and continued construction of the Oak Creek AQCS project. The increase in investing activities also reflects a reduction in the release of restricted cash related to the Point Beach bill credits.

2009 vs. 2008: Cash used in investing activities was \$333.6 million during 2009, which was \$120.9 million higher than 2008. This increase primarily reflects a reduction in the release of restricted cash related to the Point Beach bill credits, partially offset by lower capital expenditures during 2009. During 2009, we released \$153.1 million less from restricted cash as compared to 2008. In September 2007, we sold Point Beach and placed approximately \$924 million of cash in restricted accounts to be used for the payment of taxes and for the benefit of our customers. We release the restricted cash, adjusted for taxes, as we issue bill credits to our customers, which is reflected as an amortization of the gain on our income statement. In addition, during 2009, our capital expenditures decreased by \$42.6 million as compared to 2008, primarily due to the completion of our Blue Sky Green Field wind project in 2008.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Financing Activities

The following table summarizes our cash flows from financing activities:

	2010	2009	2008
	(Millions of Dollars)		
Dividends to Wisconsin Energy	(\$179.6)	(\$179.6)	(\$367.0)
Capital Contribution from Wisconsin Energy	100.0	100.0	-
Net increase in Debt	117.9	176.2	225.3
Other	12.3	0.3	(2.1)
Cash Provided by (Used in) Financing	<u>\$50.6</u>	<u>\$96.9</u>	<u>(\$143.8)</u>

2010 vs. 2009: Cash provided by financing activities was \$50.6 million during 2010 compared to \$96.9 million provided by financing activities during 2009. The decrease in financing cash flows is primarily related to changes in our debt levels. In 2010, we increased our debt levels by \$117.9 million compared to an increase of \$176.2 million during 2009.

2009 vs. 2008: Cash provided by financing activities was \$96.9 million during 2009 compared to \$143.8 million used in financing activities during 2008. During 2009, we issued \$250 million of debentures. The net proceeds were used to repay short-term debt and for other general corporate purposes. In addition, we repurchased \$147 million of outstanding tax-exempt bonds in August 2009.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

We anticipate meeting our capital requirements during 2011 primarily through internally generated funds and short-term borrowings, supplemented as necessary by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors, and an equity contribution from our parent. Beyond 2011, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings, the issuance of debt securities and equity contributions from our parent.

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 arrangement, access to capital markets and internally generated cash.

We maintain a bank back-up credit facility that provides liquidity support for our obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2010, we had approximately \$496.6 million of available, undrawn lines under our bank back-up credit facility, and approximately \$210.5 million of commercial paper outstanding that was supported by the available lines of credit. For additional information regarding our commercial paper balances during 2010, see Note J -- Short-Term Debt in the Notes to Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 facility as of December 31, 2010:

Total Facility	Letters of Credit	Credit Available	Facility Expiration
(Millions of Dollars)			
\$500.0	\$3.4	\$496.6	December 2013

On December 20, 2010, we entered into an unsecured three-year \$500 million bank back-up credit facility to replace a \$500 million five-year credit facility with an expiration date of March 2011. This new facility will expire in December 2013. This facility has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our consolidated capitalization structure as of December 31:

Capitalization Structure	2010		2009	
	(Millions of Dollars)			
Common Equity	\$3,065.1	41.5%	\$2,804.2	46.4%
Preferred Stock	30.4	0.4%	30.4	0.5%
Long-Term Debt (a)	1,970.9	26.7%	1,969.5	32.5%
Capital Lease Obligations (a)	2,082.6	28.2%	1,123.3	18.6%
Short-Term Debt (b)	238.1	3.2%	120.2	2.0%
Total	<u>\$7,387.1</u>	<u>100.0%</u>	<u>\$6,047.6</u>	<u>100.0%</u>

(a) Includes current maturities

(b) Includes subsidiary note payable to Wisconsin Energy

We recorded an increase of approximately \$1.0 billion to our capital lease obligations in connection with OC 1 being placed in service in February 2010 and an increase of approximately \$650 million in connection with OC 2 being placed in service in January 2011. For additional information, see Note I -- Long-Term Debt and Capital Lease Obligations in the Notes to Consolidated Financial Statements.

We are the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of \$147 million. In August 2009, we terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. We issued commercial paper to fund the purchase of the bonds. As of December 31, 2010, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by us. Depending on market conditions and other factors, we 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 2011 and 2012. As a result of this change in law, we anticipate that certain projects will benefit from the increased bonus depreciation in 2011 and 2012. We estimate \$60 million in cash benefits from bonus depreciation in 2011 and \$180 million in 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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

December 31, 2010, we estimate that the collateral or the termination payment required under these agreements totaled approximately \$195.8 million. Generally, collateral may be provided by a 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 2010, Moody's downgraded our long-term debt ratings (senior unsecured to A2 from A1; commercial paper, P-1). Moody's affirmed our stable ratings outlook.

In July 2010, S&P affirmed our ratings (commercial paper, A-2; senior unsecured, A-) and our stable ratings outlook.

In June 2010, Fitch affirmed our ratings (commercial paper, F1; senior unsecured, A+) and revised our ratings outlook from negative to stable.

Subject to other factors affecting the credit markets as a whole, we believe our current security 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 if it decides that the circumstances warrant the change.

Capital Requirements

Capital Expenditures: Our estimated 2011, 2012 and 2013 capital expenditures are as follows:

Capital Expenditures	2011	2012	2013
	(Millions of Dollars)		
Renewable	\$332.9	\$131.9	\$10.4
Environmental	165.5	67.5	71.1
Base Spending	343.3	351.5	336.8
Total	\$841.7	\$550.9	\$418.3

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 us.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately \$950 million as of December 31, 2010. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

In January 2009, we contributed approximately \$265 million to Wisconsin Energy's qualified pension plan due to poor investment returns during 2008. We did not make contributions to the plan during 2010 as it was adequately funded. In January 2011, we contributed \$99.1 million to the qualified pension plan. 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 M -- 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 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,

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note N -- Guarantees and Note F -- Variable Interest Entities in the Notes to Consolidated Financial Statements in this report.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2010:

Contractual Obligations (a)	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	\$3,890.8	\$111.1	\$515.3	\$718.1	\$2,546.3
Capital Lease Obligations (c)	8,079.9	314.2	632.7	657.3	6,475.7
Operating Lease Obligations (d)	86.2	22.8	22.8	7.9	32.7
Purchase Obligations (e)	12,412.1	910.3	1,359.3	842.6	9,299.9
Other Long-Term Liabilities (f)	86.0	86.0	-	-	-
Total Contractual Obligations	\$24,555.0	\$1,444.4	\$2,530.1	\$2,225.9	\$18,354.6

- (a) The amounts included in the table are calculated using current market prices, forward curves and other estimates.
- (b) Principal and interest payments on Long-Term Debt (excluding capital lease obligations).
- (c) Capital Lease Obligations for power purchase commitments and the PTF leases. For information regarding the capital lease obligation for OC 2, which was placed into service on January 12, 2011, see Note S -- Subsequent Events.
- (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 and for construction, information technology and other services for utility operations. This includes the power purchase agreement for all of the energy produced by Point Beach.
- (f) Other Long-Term Liabilities include our portion of the expected 2011 supplemental executive retirement plan obligation. For additional information on employer contributions to Wisconsin Energy's benefit plans, see Note M -- 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. For additional information regarding these liabilities, refer to Note G -- Income Taxes in the Notes to Consolidated Financial Statements in this report.

Our 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: We account for our regulated operations in accordance with accounting guidance for regulated entities. Our rates are determined by regulatory authorities. Our primary regulator

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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.

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 our risk of electric fuel cost fluctuation. If cumulative fuel and purchased power costs for electric utility operations deviate from a prescribed range (plus or minus 2% for 2010) when compared to the costs projected in the most recent retail rate proceeding, retail electric rates may be adjusted prospectively. Beginning in 2011, the PSCW has 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% for 2011). Under the rules, any 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 Rates and Regulatory Matters.

The PSCW has authorized dollar for dollar recovery for the majority of natural gas costs for our gas utility operations through a GCRM, which mitigates most of the risk of gas cost variations. For information concerning the electric utility fuel cost adjustment procedure and our natural gas utility's GCRM, see Rates and Regulatory Matters.

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.

In March 2005, the PSCW authorized the use of the escrow method of accounting for bad debt costs allowing for deferral of Wisconsin residential bad debt expense that exceeds amounts allowed in rates. As part of the January 2010 PSCW rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs through December 31, 2011.

As a result of our GCRM, our gas distribution operation receives 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.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Our 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 our service territory during 2010, 2009 and 2008, 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, 2010. Borrowing levels under these arrangements vary from period to period depending

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 at December 31, 2010 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2010, we had \$210.5 million of commercial paper outstanding with a weighted-average interest rate of 0.25% 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 \$2.1 million before taxes from commercial paper and by \$1.5 million before taxes from variable rate long-term debt outstanding.

Marketable Securities Return: We use various trusts to fund our pension and Other Post-Retirement Employee Benefit (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, 2010 was approximately:

	<u>Millions of Dollars</u>
Pension trust funds	\$813.7
Other post-retirement benefits trust funds	\$135.9

The expected long-term rate of return on plan assets is 7.25% and 7.5%, respectively, for both the pension and other post-retirement benefit plans for 2011.

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.

Wisconsin Energy consulted with its investment advisors on an annual basis to help it 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 at the beginning of this report and Risk Factors in Item 1A.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

POWER THE FUTURE

As of January 12, 2011, 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	\$ 1,355 million
OC 2	January 2011	\$ 668 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 We Power's ownership percentage.

We are leasing the PTF units from We Power under long-term leases. We are recovering the lease payments associated with PWGS 1, PWGS 2 and OC 1 in our rates as authorized by the PSCW, the MPSC and FERC. We are recovering the lease payment associated with OC 2 as authorized by the PSCW and FERC, and will request authorization from the MPSC with the next rate case.

Background: The PSCW issued orders granting CPCNs for the construction of the PWGS and the Oak Creek expansion in 2002 and 2003, respectively.

PWGS consists of two 545 MW natural gas-fired combined cycle generating units on the site of our 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 is located adjacent to the site of our existing Oak Creek Power Plant. OC 1 and OC 2 were placed into service on February 2, 2010 and January 12, 2011, respectively. The total cost for the two units was set at \$2.191 billion. We Power estimates that the final cost of the Oak Creek expansion is approximately \$191.0 million, or 8.7%, over the amount initially approved by the PSCW, of which its share is \$162.0 million. The additional amount includes the amounts payable to 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 provide for a guaranteed in-service date of September 29, 2009 for OC 1 and September 29, 2010 for OC 2, and impose liquidated damages of \$250,000 per day, of which the amount payable to us by Elm Road Generating Station Supercritical, LLC (ERGSS) is approximately \$208,350 per day, for failure to achieve the guaranteed in-service date unless the delays result from force majeure conditions or an excused event. In light of the weather delays incurred on the project and other factors, we, along with ERGSS, expect to request authorization from the PSCW to recover all costs associated with the units.

ERGSS is 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, ERGSS granted Bechtel total schedule relief of 120 days for OC 1 and 81 days for OC 2. Subject to PSCW review, all liquidated damages collected by us from ERGSS are for the benefit of our customers.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Lease Terms: The PSCW approved the lease agreements and related documents under which we 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.

WPDES Permit: In order to resolve all outstanding challenges to the Wisconsin Pollution Discharge Elimination System (WPDES) permit issued by the WDNR in connection with the Oak Creek expansion, a settlement agreement was reached with Clean Wisconsin, Inc. and Sierra Club, in which we committed to contribute our share of \$5 million (approximately \$4.2 million) towards projects to reduce greenhouse gas emissions. We also agreed (i) for the 25 year period ending 2034, subject to regulatory approval and cost recovery, to contribute our share of up to \$4 million per year (approximately \$3.3 million) to fund projects to address Lake Michigan water quality, and (ii) subject to regulatory approval and cost recovery, to develop new solar and biomass generation projects. We also agreed to support state legislation to increase the renewable portfolio standard to 10% by 2013 and 25% by 2025, and to retire 116 MW of coal-fired generation at our Presque Isle Power Plant.

In its December 2009 decision, based upon a proposal submitted by the parties to the settlement agreement, the PSCW authorized recovery of \$2.0 million per year for 2010 and 2011 related to costs associated with projects to address Lake Michigan water quality and recovery of \$2.0 million of the second \$2.5 million payment related to projects to reduce greenhouse gas emissions. Based upon this decision, the parties are proceeding to carry out the settlement agreement. We are responsible for our pro rata share of these payments.

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 and electric transmission service rates. The MPSC regulates our retail electric rates in the state of Michigan. We estimate that approximately 87% 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. We anticipate filing a rate case in 2011 for rates effective in January 2012. 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/.

2010 Wisconsin Rate Case: In March 2009, we initiated rate proceedings with the PSCW. We initially asked the PSCW to approve a rate increase for our Wisconsin retail electric customers of approximately \$76.5 million, or 2.8%, and a rate increase for our natural gas customers of approximately \$22.1 million,

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

or 3.6%. In addition, we requested increases of approximately \$1.4 million, or 5.8%, and approximately \$1.3 million, or 6.8%, for our Milwaukee Downtown (Valley) steam utility customers and Milwaukee County steam utility customers, respectively.

In July 2009, we filed supplemental testimony with the PSCW updating our 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 us increasing our request from \$76.5 million to \$126.0 million.

In December 2009, the PSCW authorized rate adjustments related to our request 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 our retail electric rates, 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; and
- A decrease of approximately \$0.4 million (1.65%) for our Valley steam utility customers and a decrease of approximately \$0.1 million (0.47%) for our Milwaukee County steam utility customers.

These rate adjustments became effective January 1, 2010. In addition, the PSCW lowered our authorized return on equity from 10.75% to 10.4%.

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
- We 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.

As part of its final decision in the 2010 rate case, the PSCW authorized us to reopen the docket in 2010 to review updated 2011 fuel costs. On September 3, 2010, we 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. We 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 currently embedded in rates. In December 2010, we reduced our request by approximately \$6 million. The net increase of \$32.4 million is being driven primarily by an increase in the delivered cost of coal. We expect to receive approval for the increased rates in the first quarter of 2011.

2010 Michigan Rate Increase Request: In July 2009, we filed a \$42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. In December 2009, the MPSC approved our 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. On November 12, 2010, the mines filed a Claim of Appeal of the October 2010 order with the Michigan Court of Appeals. On December 28, 2010, the MPSC filed a Motion for Remand with the Court of Appeals.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

2008 Wisconsin Rate Increase: During 2007, we initiated rate proceedings. In January 2008, the PSCW approved pricing increases for us as follows:

- \$389.1 million (17.2%) in electric rates - the pricing increase was offset by bill credits in 2008 and 2009;
- \$4.0 million (0.6%) for natural gas service; and
- \$3.6 million (11.2%) for steam service.

In addition, the PSCW lowered our return on equity from 11.2% to 10.75%. The PSCW also determined that \$85.0 million of the Point Beach proceeds should be immediately applied to offset certain regulatory assets.

2008 Michigan Rate Increase: In January 2008, we filed a rate increase request with the MPSC. This request represented an increase in electric rates of 14.7%, or \$22.0 million, to support the growing demand for electricity at that time, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational expenses. In November 2008, a settlement agreement with the MPSC staff and intervenors for a rate increase of \$7.2 million, or 4.6%, was approved by the MPSC, effective January 1, 2009.

Limited Rate Adjustment Requests

2010 Fuel Recovery Request: In February 2010, we 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 being 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. The revenues that we collect are subject to refund with interest at a rate of 10.4%. We expect PSCW review and final approval in the first quarter of 2011.

2009 Fuel Order: We operate under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation of electricity for our retail customers in Wisconsin. 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, we 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, we filed a request with the PSCW to decrease annual Wisconsin retail electric rates by \$67.2 million because we forecasted that our 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 is currently auditing the fuel costs for the year 2009 to determine whether we 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.

The PSCW staff issued for comment a memorandum detailing different alternatives for calculating excess revenues. We do not believe the amount to be refunded to customers, if any, should be material. We anticipate a decision in this matter in the first quarter of 2011.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Other Rate Matters

Oak Creek Air Quality Control System Approval: In July 2008, we received approval from the PSCW granting us 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 \$780 million (\$910 million including AFUDC). The cost of constructing these facilities is included in our estimates of the costs to implement the Consent Decree with the EPA.

Michigan Legislation: During October 2008, Michigan enacted legislation to make significant changes in regulatory procedures, which should provide for more timely cost recovery. Public Act 286 allows the use of a forward-looking test year in rate cases, rather than historical data, and allows us to put interim rates into effect six months after filing a complete case. Rate filings for which an order is not issued within 12 months are deemed approved. In addition, we could seek a CPCN for new investment, and could recover interest on the investment during construction. Public Act 286 also gives the MPSC expanded authority over proposed mergers and acquisitions, and requires action within 180 days of filing.

Wisconsin Fuel Rules: Embedded within our base rates is an amount to recover fuel costs. Under the Wisconsin fuel rules prior to January 1, 2011, no adjustments were made to rates under the fuel cost adjustment clause as long as fuel and purchased power costs were expected to be within a band of the costs embedded in current rates for the 12-month period ending December 31. If, however, annual fuel costs were expected to fall outside of the band, and actual costs fell outside of established fuel bands, then we could file for a change in fuel recoveries on a prospective basis.

In April 2010, the Wisconsin legislature passed the Fuel Rule Bill, and the Governor signed it in May 2010. This bill instructed the PSCW 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. In August 2010, the PSCW proposed new fuel rules pursuant to this legislation, which the Wisconsin legislature reviewed and sent back to the PSCW for additional rule-making. In December 2010, the PSCW revised the proposed rules as requested by the legislature and sent the revised rules back to the legislature for review. The new fuel rules are now in effect and fuel cost plans approved by the PSCW after January 1, 2011 will be subject to the new rules.

Electric Transmission Cost Recovery: We divested our 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, 2010, we had deferred \$138.0 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 a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar for dollar recovery of gas costs. Prior to 2010, there was an incentive mechanism under the GCRM that allowed for increased revenues if we acquired gas at prices lower than benchmarks approved by the PSCW. However, as part of the January 2010 PSCW rate order, the PSCW approved changing from an incentive method to a modified one for one method. The new method does not have revenue sharing. The GCRM 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 most other utilities in Wisconsin.

Bad Debt Costs: In March 2005, the PSCW approved our use of escrow accounting for residential bad debt costs. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

residential bad debt expense that exceeds amounts allowed in rates. As part of the January 2010 PSCW rate order, the escrow accounting method for bad debt costs was extended through December 31, 2011.

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 \$41 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. Our baseline renewable energy percentage is 2.27%. Under Act 141, we could not decrease our renewable energy percentage for the years 2006-2009, and for the years 2010-2014, we must increase our renewable energy percentage at least two percentage points to a level of 4.27%. As of December 31, 2010, our renewable energy percentage is at 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, we have developed and contracted for several hundred megawatts of wind generation and are in the process of seeking permits and approvals for approximately 50 megawatts of biomass fueled generation. Assuming the additional wind generation currently under construction and the proposed biomass project is approved and completed on schedule, we expect to be in compliance with Act 141 through the year 2015. To remain in compliance with Act 141, we would need to construct or contract for the equivalent of approximately 500 MW of additional renewable generating capacity by 2020. 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 1.2% of utilities' annual operating revenues be used to fund these programs. The funding required by Act 141 increased to 1.5% of annual operating revenues in 2011 and is scheduled to increase to 1.9% 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: In May 2008, the Blue Sky Green Field wind farm project, which has 88 turbines with an installed capacity of 145 MW, reached commercial operation. In July 2008, we completed the purchase of rights to a new wind farm site in Central Wisconsin, Glacier Hills Wind Park, and filed a request for a CPCN with the PSCW in October 2008. The PSCW approved the CPCN in January 2010. We currently expect to install 90 wind turbines with a total generating capacity of

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

approximately 162 MW. This project is expected to cost between \$360 million and \$370 million, excluding AFUDC. Construction commenced in May 2010, and we anticipate 2012 will be the first full year of operation.

In September 2009, we announced plans to construct 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. We believe the biomass plant will be eligible for the federal production tax credit. We currently expect to invest approximately \$255 million, excluding AFUDC, in the plant and for it to be completed during the fall of 2013, subject to regulatory and other approvals. In March 2010, we filed a request for a Certificate of Authority for the project with the PSCW. We anticipate a decision from the PSCW during the first quarter of 2011.

Edgewater Generating Unit 5: During the fourth quarter of 2009, we reached a contingent agreement to sell our 25% interest in Edgewater Generating Unit 5 to WPL for our net book value, including working capital. In March 2010, the agreement became effective and we are in the process of receiving regulatory approvals. We received approval for the sale from FERC in June 2010, and from the PSCW in November 2010. We are currently working with the MPSC to obtain approval on terms that are acceptable to us. Assuming completion of the sale, we expect to realize proceeds of between \$40 million and \$45 million depending on the working capital balances and our level of capital investment in the unit prior to the sale. The contractual deadline to complete the sale is June 30, 2011.

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 2010 and 2009. 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 2011. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures.

ENVIRONMENTAL MATTERS

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 us include, but are not limited to, current and future regulation of: (1) air emissions such as CO₂, SO₂, NO_x, fine particulates and mercury; (2) disposal of coal combustion by-products such as fly ash; and (3) remediation of impacted properties, including former manufactured gas plant sites.

We are currently pursuing a proactive strategy to manage our environmental compliance obligations, including: (1) improving our overall energy portfolio by adding more efficient generation as part of Wisconsin Energy's PTF strategy; (2) developing additional sources of renewable electric energy supply; (3) reviewing water quality matters such as discharge limits and cooling water requirements; (4) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (5) implementing a Consent Decree with the EPA to reduce emissions of SO₂ and

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

NO_x by more than 65% by 2013; (6) evaluating and implementing improvements to our cooling water intake systems; (7) continuing the beneficial re-use of ash and other solid products from coal-fired generating units; and (8) conducting the clean-up of former manufactured gas plant sites.

Air Quality

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. States were required to develop and submit a State Implementation Plan (SIP) to the EPA by June 2007 to demonstrate how they intended to comply with the 8-hour ozone ambient air quality standard. Instead of submitting a SIP, Wisconsin submitted a request to redesignate all counties in southeastern Wisconsin as in attainment with the standard. In addition to the request for redesignation, Wisconsin also adopted the Reasonably Available Control Technology (RACT) rule that applies to emissions from our power plants in the affected areas of Wisconsin. Compliance with the NO_x emission reduction requirements under the Consent Decree has substantially mitigated costs to comply with the RACT rule. In March 2008, the EPA issued a determination that the state of Wisconsin had failed to submit a SIP. In a separate action in May 2008, the EPA redesignated one of the 10 counties, Kewaunee County, as in attainment. In September 2009, Wisconsin submitted a SIP to the EPA. Based on our review of this submittal, we do not believe we would be subject to any further requirements to reduce emissions. In July 2010, the EPA redesignated an additional two counties, Manitowoc and Door, as in attainment. Although the EPA has yet to take action on redesignation of the remaining 7 counties due to continuing issues related to a portion of the SIP, Volatile Organic Compounds (VOC) RACT rules that do not apply to our facilities, it issued a finding of attainment in December 2010 for the remaining 7 counties in southeastern Wisconsin. In order for the EPA to redesignate these counties, the state must revise, submit and receive EPA approval of revised VOC RACT rules. Pending redesignation, we will continue to be subject to more stringent permitting standards for new or revised facilities in the affected 7 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. In a December 2010 motion, the EPA asked that the litigation challenging the 2008 ozone National Ambient Air Quality Standards (NAAQS) be set aside. The EPA indicates that it now expects to complete its reconsideration rulemaking by July 29, 2011. Although it is likely that additional counties, including the 10 in southeastern Wisconsin discussed above, may be designated as non-attainment areas under the revised standard, until those designations become final and until any potential additional rules are adopted, we are unable to predict the impact on the operation of our coal-fired generation facilities.

Fine Particulate Standard: In December 2004, the EPA designated Fine Particulate Matter (PM_{2.5}) non-attainment areas. All counties in Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. In December 2006, a more restrictive federal standard became effective; however, on February 24, 2009, the D.C. Circuit Court of Appeals issued a decision on the revised standard and remanded it back to the EPA for revision. The court's decision will likely result in an even more stringent annual PM_{2.5} standard. 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 until 2012 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 cannot be determined at this time. Similarly, until the EPA revises the 2006 standard consistent with the court's decision and the states develop rules and submit SIPs to the EPA to demonstrate how they intend to comply with that standard, we are unable to predict the impact of this more restrictive standard on the operation of our coal-fired generation facilities.

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, if modifications to an existing facility would result in increases in PM_{2.5} emissions, we would potentially need to obtain an air pollution control construction permit, including requirements to control emissions to levels which represent best available control technology or lowest achievable emission rate.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Sulfur Dioxide Standard: The EPA adopted its final rule revising the NAAQS for SO₂. The rule became effective August 23, 2010. If the revised standard results in the designation of new non-attainment areas, it could potentially have an adverse effect on our facilities in those areas. 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.

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.

Clean Air Interstate Rule: The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005 to facilitate the states in meeting the 8-hour Ozone and Fine Particulate Matter standards by addressing the regional transport of SO₂ and NO_x. In 2008, the U.S. Court of Appeals for the D.C. Circuit invalidated several aspects of CAIR and remanded the rule to the EPA to promulgate a replacement rule.

In July 2010, the EPA proposed a Transport Rule to replace CAIR. The proposed Transport Rule, like CAIR, would establish individual state caps for the emissions of SO₂ and NO_x from electric generating units in the eastern half of the United States, including Michigan and Wisconsin. The CAIR is in effect as of 2009 for NO_x and 2010 for SO₂, but will be replaced with the new requirements of the Transport Rule, if adopted. The Transport Rule may require new reductions in 2012 for NO_x and SO₂ and additional reductions in 2014 for SO₂ for some states, including Wisconsin and Michigan. According to the EPA, the Transport Rule and other actions by States is expected to result in a 71% reduction of SO₂ and 52% reduction of NO_x emissions from power plants in the eastern United States by 2014 from 2005 emission levels.

We submitted comments on the proposed rule in October 2010. The EPA intends to finalize the rule in mid-2011.

We previously determined that compliance with the NO_x and SO₂ emission reductions requirements under the Consent Decree that we entered into with the EPA in April 2003 would substantially mitigate costs to comply with CAIR and would achieve the levels necessary under at least the first phase of CAIR. The proposed limits under the Transport Rule appear to be more stringent and could result in the need for additional expenditures by 2014.

Mercury and Other Hazardous Air Pollutants: The EPA issued the final Clean Air Mercury Rule (CAMR) in March 2005, addressing mercury emissions from new and existing coal-fired power plants. The federal rule was challenged by a number of states including Wisconsin and Michigan. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR and sent the rule back to the EPA for reconsideration.

In December 2008, a number of environmental groups filed a complaint with the D.C. Circuit asking that the court place the EPA on a schedule for promulgating Maximum Achievable Control Technology (MACT) limits for fossil-fuel fired electric generating units to address hazardous air pollutants, including mercury. In October 2009, the EPA published notice of a proposed consent decree in connection with this litigation that would place the EPA on a schedule to set a MACT rule for coal and oil-fired electric generating units in 2011. In April 2010, the D.C. District Court approved a settlement agreement between the EPA and the plaintiffs in the litigation setting a firm schedule for the remanded rule-making. This settlement requires that the EPA issue a proposed rule by March 16, 2011 and a final rule by November 16, 2011. The EPA is currently in the process of developing the proposed MACT rule, which is expected to reduce emissions of numerous hazardous air pollutants, including mercury. We are unable to predict the impact on the operation of our existing coal-fired generation facilities until a proposed and final rule is issued.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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

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 various scenarios for regulating coal combustion products including classifying them as hazardous waste. We submitted comments on the proposed rule in November 2010. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program. Curtailing our program could result in the loss of a revenue stream that helps to offset the cost of pollution control equipment and the activities necessary to collect the coal combustion products.

In addition, 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.

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, SO₂ and ammonia. States were required to submit SIPs to implement CAVR by December 2007. Wisconsin has not yet submitted a SIP. Michigan submitted a SIP, which was partially approved. In response to a citizen suit, in January 2009, the EPA issued a finding of failure to 37 states, including Wisconsin and Michigan, regarding their failure to submit SIPs. The finding started a two-year review window for the EPA to issue Federal Implementation Plans (FIPs), unless a state submits and receives SIP approval. Wisconsin has not yet released a SIP, nor made a SIP submittal to the EPA. Michigan submitted a complete SIP in November 2010. The EPA, however, has not yet taken any action to approve this SIP, nor issue a FIP to any states, including Michigan and Wisconsin.

Wisconsin and Michigan have completed the BART rules, which cover one aspect of the CAVR regulations. Wisconsin BART rules became effective in July 2008 and Michigan BART rules became effective in September 2008.

Both Wisconsin and Michigan BART rules are based, in part, on utility reductions of NO_x and SO₂ that were expected to occur under CAIR. Therefore, we will not be able to determine final impacts of these rules until the EPA completes a new rule, which it intends to finalize by mid-2011, pursuant to a ruling by the U.S. Court of Appeals for the D.C. Circuit.

EPA Consent Decree: In April 2003, we reached a Consent Decree with the EPA in which we agreed to significantly reduce air emissions from certain of our 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. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 will be 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. Legislative and regulatory proposals that would impose mandatory restrictions on CO₂ emissions continue to be considered in the U.S. Congress and by the EPA, and the President and his administration have made it clear that they are focused on reducing CO₂ emissions, through legislation and/or regulation. Although the ultimate outcome of these efforts cannot be determined at this time, mandatory restrictions on our CO₂ emissions could result in significant compliance costs that could affect future results of operations, cash flows and financial condition. For additional information, see the caption "We may face significant costs to comply with the regulation of greenhouse gas emissions." under Item 1A Risk Factors in this report.

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 impact. In September 2004, the EPA adopted rules for existing facilities to minimize the potential adverse impacts to aquatic organisms associated with water withdrawals from cooling water intakes. Costs associated with implementation of the 316(b) rules for our Oak Creek Power Plant, We Power's Oak Creek expansion and PWGS were included in project costs.

In January 2007, the Federal Court of Appeals for the Second Circuit found certain portions of the rule impermissible, including portions that permitted approval of water intake system technologies based on a cost-benefit analysis, and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. In April 2009, the United States Supreme Court reversed the Second Circuit regarding the use of cost-benefit analysis and held that it was permissible for the EPA to rely on cost-benefit analysis in setting national performance standards and in providing variances from those standards. The Supreme Court remanded the case for further proceedings consistent with its opinion.

On December 3, 2010, the Federal District Court in New York approved a settlement agreement between the EPA and Riverkeeper Inc. (plaintiff in the litigation) setting a firm schedule for the remanded Section 316(b) rulemaking. This settlement requires that the EPA issue a proposed rule by March 14, 2011 and a final rule by July 27, 2012. Until the EPA completes its reconsideration and rulemaking, we cannot predict what impact these changes may have on our facilities. The decision will not affect the new units at the Oak Creek expansion because those units were permitted based on a BTA decision under the Phase I rule for new facilities.

In December 2009, the EPA published its determination that revision of the current effluent guidelines for steam electric generating units was warranted, and proposed a rulemaking process to adopt such revisions by 2013. Revisions to the current effluent guidelines are expected to result in more stringent standards that may result in the installation of additional controls. Until the EPA completes its rulemaking process, however, we cannot predict what impact these new standards may have on our facilities.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Other Environmental Matters

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 Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

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

LEGAL MATTERS

Cash Balance Pension Plan: On June 30, 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. Counsel representing the plaintiff is attempting to seek class certification for other similarly situated plaintiffs. The complaint alleges 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 are 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. On September 6, 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy Corporation as a defendant. The plaintiff has not specified the amount of relief he is seeking. An adverse outcome of this lawsuit could have a material adverse effect on Plan funding and expense and our results of operations. Although we are currently unable to predict the final outcome or impact of this litigation, we are aware that courts in two similar lawsuits filed in Wisconsin found that the interest crediting rates applied by the pension plan involved in those cases were not in compliance with ERISA.

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.

In recent years, dairy farmers have commenced actions or made claims against us for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of our 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 this case, 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 us. Another stray voltage lawsuit was filed against us on January 27, 2011. We do not believe these lawsuits have merit and we will vigorously defend them. These lawsuits are not expected to have a material adverse effect on our financial statements. We continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Used Nuclear Fuel Storage and Disposal: During our ownership of Point Beach, we were 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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

Unit 1 and in March 2013 for Unit 2 before they were renewed 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 we paid a total of \$215.2 million into the Nuclear Waste Fund over the life of our 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, we filed a complaint in November 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted our 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 our favor, 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 expect to receive in the first quarter of 2011. We anticipate that this amount, net of costs incurred, will be returned to customers in future rate cases.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large RTOs, 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 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. The Energy Policy Act, among other things, amended federal energy laws and provided FERC with new oversight responsibilities.

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 territory 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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 (LSEs) located in the service territories of each MISO transmission owner. In February 2008, FERC issued several orders confirming 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 \$7.5 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, we filed for rehearing and/or clarification with FERC, along with several other parties.

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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

(ARRs) and Financial Transmission Rights (FTRs). ARR 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, 2010 through May 31, 2011. 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 for information on new accounting pronouncements.

International Financial Reporting Standards: During 2009, the SEC announced a "roadmap" for U.S. registrants that, if adopted, would require U.S. companies to follow IFRS instead of GAAP. The SEC guidelines, in their current form, would require us to adopt IFRS in 2014.

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 also may 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: We 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 companies would expense. The actions of our regulators may also require us to accrue liabilities that non-regulated entities would not. As of December 31, 2010, we had \$1,056.0 million in regulatory assets and \$672.6 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, continued deferral of certain regulatory asset and liability amounts on our books, as allowed under regulatory accounting, may no longer be appropriate and the unamortized regulatory assets net of the 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.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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

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

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

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	\$5.6
0.5% decrease in expected rate of return on plan assets	\$4.1

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note M -- 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, our regulators 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	\$2.5
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	\$0.7

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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont'd)

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 operating revenues during 2010 of approximately \$3.5 billion included accrued revenues of \$208.7 million as of December 31, 2010.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in this report for information concerning potential market risks to which we are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED INCOME STATEMENTS

Year Ended December 31

	<u>2010</u>	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)		
Operating Revenues	\$ 3,456.7	\$ 3,288.3	\$ 3,410.1
Operating Expenses			
Fuel and purchased power	1,104.7	1,064.5	1,242.3
Cost of gas sold	316.0	389.7	526.4
Other operation and maintenance	1,432.5	1,231.7	1,295.2
Depreciation and amortization	216.2	265.1	256.0
Property and revenue taxes	96.5	99.1	96.4
Total Operating Expenses	<u>3,165.9</u>	<u>3,050.1</u>	<u>3,416.3</u>
Amortization of Gain	<u>198.4</u>	<u>230.7</u>	<u>488.1</u>
Operating Income	489.2	468.9	481.9
Equity in Earnings of Transmission Affiliate	52.7	51.9	45.4
Other Income and Deductions, net	39.8	25.8	9.9
Interest Expense, net	<u>101.5</u>	<u>100.3</u>	<u>86.6</u>
Income Before Income Taxes	480.2	446.3	450.6
Income Taxes	<u>164.8</u>	<u>157.7</u>	<u>169.3</u>
Net Income	315.4	288.6	281.3
Preferred Stock Dividend Requirement	<u>1.2</u>	<u>1.2</u>	<u>1.2</u>
Earnings Available for Common Stockholder	<u>\$ 314.2</u>	<u>\$ 287.4</u>	<u>\$ 280.1</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2010	2009
	(Millions of Dollars)	
Property, Plant and Equipment		
Electric	\$ 6,612.1	\$ 6,477.5
Gas	882.4	850.0
Steam	91.4	89.9
Common	239.4	239.1
Other	60.1	61.5
	<u>7,885.4</u>	<u>7,718.0</u>
Accumulated depreciation	<u>(2,879.7)</u>	<u>(2,822.6)</u>
	5,005.7	4,895.4
Construction work in progress	803.3	382.6
Leased facilities, net	<u>1,850.7</u>	<u>959.6</u>
Net Property, Plant and Equipment	7,659.7	6,237.6
Investments		
Equity investment in transmission affiliate	290.6	276.7
Other	0.5	0.5
Total Investments	<u>291.1</u>	<u>277.2</u>
Current Assets		
Cash and cash equivalents	23.3	18.3
Restricted cash	8.3	194.5
Accounts receivable, net of allowance for doubtful accounts of \$34.2 and \$31.5	260.4	223.0
Accounts receivable from related parties	23.3	22.8
Accrued revenues	208.7	212.8
Materials, supplies and inventories	321.8	321.5
Prepayments	131.0	122.2
Regulatory assets	47.0	48.5
Other	20.4	25.5
Total Current Assets	<u>1,044.2</u>	<u>1,189.1</u>
Deferred Charges and Other Assets		
Regulatory assets	1,009.0	1,014.6
Other	166.7	152.7
Total Deferred Charges and Other Assets	<u>1,175.7</u>	<u>1,167.3</u>
Total Assets	<u>\$ 10,170.7</u>	<u>\$ 8,871.2</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
December 31

CAPITALIZATION AND LIABILITIES

	<u>2010</u>	<u>2009</u>
	(Millions of Dollars)	
Capitalization		
Common equity	\$ 3,065.1	\$ 2,804.2
Preferred stock	30.4	30.4
Long-term debt	1,970.9	1,969.5
Capital lease obligations	<u>2,060.8</u>	<u>1,111.3</u>
Total Capitalization	7,127.2	5,915.4
Current Liabilities		
Long-term debt and capital lease obligations due currently	21.8	12.0
Short-term debt	210.5	92.0
Subsidiary note payable to Wisconsin Energy	27.6	28.2
Accounts payable	234.8	207.0
Accounts payable to related parties	83.7	79.9
Payroll and vacation accrued	68.8	64.9
Accrued taxes	11.6	50.5
Accrued interest	13.6	13.8
Regulatory liabilities	14.5	220.8
Other	<u>99.9</u>	<u>100.3</u>
Total Current Liabilities	786.8	869.4
Deferred Credits and Other Liabilities		
Regulatory liabilities	658.1	591.3
Deferred income taxes - long-term	925.4	833.8
Accumulated deferred investment tax credits	32.3	35.6
Asset retirement obligations	50.8	52.6
Pension and other benefit obligations	403.7	374.2
Other	<u>186.4</u>	<u>198.9</u>
Total Deferred Credits and Other Liabilities	2,256.7	2,086.4
Commitments and Contingencies (Note Q)		
Total Capitalization and Liabilities	<u>\$ 10,170.7</u>	<u>\$ 8,871.2</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31

	2010	2009	2008
	(Millions of Dollars)		
Operating Activities			
Net income	\$ 315.4	\$ 288.6	\$ 281.3
Reconciliation to cash			
Depreciation and amortization	224.2	272.5	263.4
Amortization of gain	(198.4)	(230.7)	(488.1)
Equity in earnings of transmission affiliate	(52.7)	(51.9)	(45.4)
Distributions from transmission affiliate	43.3	40.9	34.2
Deferred income taxes and investment tax credits, net	69.6	132.3	264.6
Contributions to qualified benefit plans	-	(283.8)	(37.9)
Change in - Accounts receivable and accrued revenues	(44.0)	51.2	(5.3)
Inventories	(0.3)	(25.0)	(10.9)
Other current assets	17.0	19.6	(44.9)
Accounts payable	23.0	(64.4)	45.2
Accrued income taxes, net	(65.5)	51.1	(61.5)
Deferred costs, net	25.9	46.2	81.5
Other current liabilities	6.6	4.9	9.6
Other, net	61.1	(24.9)	77.1
Cash Provided by Operating Activities	<u>425.2</u>	<u>226.6</u>	<u>362.9</u>
Investing Activities			
Capital expenditures	(617.3)	(481.1)	(523.7)
Investment in transmission affiliate	(4.6)	(22.7)	(22.2)
Change in restricted cash	186.2	192.0	345.1
Other, net	(35.1)	(21.8)	(11.9)
Cash Used in Investing Activities	<u>(470.8)</u>	<u>(333.6)</u>	<u>(212.7)</u>
Financing Activities			
Dividends paid on common stock	(179.6)	(179.6)	(367.0)
Dividends paid on preferred stock	(1.2)	(1.2)	(1.2)
Issuance of long-term debt	-	250.0	697.0
Retirement and repurchase of long-term debt	-	(164.4)	(147.0)
Change in total short-term debt	117.9	90.6	(324.7)
Capital contribution from parent	100.0	100.0	-
Other, net	13.5	1.5	(0.9)
Cash Provided by (Used in) Financing Activities	<u>50.6</u>	<u>96.9</u>	<u>(143.8)</u>
Change in Cash and Cash Equivalents	5.0	(10.1)	6.4
Cash and Cash Equivalents at Beginning of Year	<u>18.3</u>	<u>28.4</u>	<u>22.0</u>
Cash and Cash Equivalents at End of Year	<u>\$ 23.3</u>	<u>\$ 18.3</u>	<u>\$ 28.4</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

	2010	2009
	(Millions of Dollars)	
Common Equity (See Consolidated Statements of Common Equity)		
Common stock - \$10 par value; authorized 65,000,000 shares; outstanding - 33,289,327 shares	\$ 332.9	\$ 332.9
Other paid in capital	928.7	802.4
Retained earnings	1,803.5	1,668.9
Total Common Equity	<u>3,065.1</u>	<u>2,804.2</u>
Preferred Stock		
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	<u>30.4</u>	<u>30.4</u>
Long-Term Debt		
Debentures (unsecured)		
4.50% due 2013	300.0	300.0
6.00% due 2014	300.0	300.0
6.25% due 2015	250.0	250.0
4.25% due 2019	250.0	250.0
6-1/2% due 2028	150.0	150.0
5.625% due 2033	335.0	335.0
5.70% due 2036	300.0	300.0
6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)		
2% stated rate due 2011	-	0.1
4.81% effective rate due 2030	2.0	2.0
Notes (unsecured)		
0.504% variable rate due 2016 (a)	67.0	67.0
0.504% variable rate due 2030 (a)	80.0	80.0
Variable rate notes held by us (see Note I)	(147.0)	(147.0)
Unamortized discount, net	<u>(16.1)</u>	<u>(17.6)</u>
Total Long-Term Debt	1,970.9	1,969.5
Obligations Under Capital Leases (see Note I)	<u>2,060.8</u>	<u>1,111.3</u>
Total Capitalization	<u>\$ 7,127.2</u>	<u>\$ 5,915.4</u>

(a) Variable interest rate as of December 31, 2010.

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Total
	(Millions of Dollars)			
Balance - December 31, 2007	\$ 332.9	\$ 675.3	\$ 1,648.0	\$ 2,656.2
Net income			281.3	281.3
Other comprehensive income			-	-
Comprehensive Income	-	-	281.3	281.3
Cash dividends				
Common stock			(367.0)	(367.0)
Preferred stock			(1.2)	(1.2)
Stock-based compensation		11.3		11.3
Tax benefit of exercised stock options allocated from Parent		2.2		2.2
Balance - December 31, 2008	332.9	688.8	1,561.1	2,582.8
Net income			288.6	288.6
Other comprehensive income			-	-
Comprehensive Income	-	-	288.6	288.6
Cash dividends				
Common stock			(179.6)	(179.6)
Preferred stock			(1.2)	(1.2)
Cash contribution from Parent		100.0		100.0
Stock-based compensation		9.9		9.9
Tax benefit of exercised stock options allocated from Parent		3.7		3.7
Balance - December 31, 2009	332.9	802.4	1,668.9	2,804.2
Net income			315.4	315.4
Other comprehensive income			-	-
Comprehensive Income	-	-	315.4	315.4
Cash dividends				
Common stock			(179.6)	(179.6)
Preferred stock			(1.2)	(1.2)
Cash contribution from Parent		100.0		100.0
Stock-based compensation		7.0		7.0
Tax benefit of exercised stock options allocated from Parent		19.3		19.3
Balance - December 31, 2010	<u>\$ 332.9</u>	<u>\$ 928.7</u>	<u>\$ 1,803.5</u>	<u>\$ 3,065.1</u>

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

WISCONSIN ELECTRIC POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: Wisconsin Electric Power Company (Wisconsin Electric, the Company, our, us or we), a subsidiary of Wisconsin Energy, is an electric, gas and steam utility which services electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metropolitan Milwaukee, Wisconsin. We consolidate our wholly-owned subsidiary, Bostco. Bostco had total assets of \$35.1 million as of December 31, 2010.

All intercompany transactions and balances have been eliminated 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.

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.

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.

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	2010	2009	2008
	(Millions of Dollars)		
AFUDC - Equity	\$32.4	\$15.9	\$7.5
Gain on Property Sales	4.5	1.7	2.3
Other, net	2.9	8.2	0.1
Total Other Income and Deductions, net	<u>\$39.8</u>	<u>\$25.8</u>	<u>\$9.9</u>

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Our utility depreciation rates are certified by the PSCW and MPSC and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 2.9% in 2010 and 3.6% in 2009 and 2008.

For assets other than our regulated assets and leased equipment, we accrue depreciation expense at straight-line rates over the estimated useful lives of the assets, or over the non-cancellable lease term for leased equipment.

We collect in our 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 \$564.2 million as of December 31, 2010 and \$497.5 million as of December 31, 2009.

Allowance For Funds Used During Construction: 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 and 2008, we accrued AFUDC at a rate of 9.09% as authorized by the PSCW. Consistent with the PSCW's 2008 rate order, we accrued AFUDC on 50% of all utility Construction Work in Progress (CWIP) projects except our Oak Creek AQCS project, which accrued AFUDC on 100% of CWIP. Our 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, we are recording 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. We will record AFUDC on 50% of all other electric, gas and steam utility CWIP. Our AFUDC rate starting January 1, 2010 is 8.83%.

We recorded the following AFUDC for the years ended December 31:

	2010	2009	2008
	(Millions of Dollars)		
AFUDC - Debt	\$13.5	\$6.6	\$3.0
AFUDC - Equity	\$32.4	\$15.9	\$7.5

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

<u>Materials, Supplies and Inventories</u>	<u>2010</u>	<u>2009</u>
	(Millions of Dollars)	
Fossil Fuel	\$182.3	\$181.0
Materials and Supplies	101.0	99.3
Natural Gas in Storage	38.5	41.2
Total	<u>\$321.8</u>	<u>\$321.5</u>

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 assets on the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. We defer regulatory assets pursuant to specific orders or by a generic order issued by our regulators. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). We expect to recover our

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 E.

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

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

Restricted Cash: Cash proceeds that we received from the sale of Point Beach that are to be used for the benefit of our customers are recorded as restricted cash. As of December 31, 2010, 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.

Restrictions: Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. We do not believe that these restrictions will materially affect our operations. For further information, see Note H.

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 23.0% in ATC as of December 31, 2010 and 2009. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note P.

Income Taxes: We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized.

Investment tax credits related to regulated utility assets are recorded as a deferred credit on the balance sheet and amortized to income over the applicable service lives of related properties in accordance with regulatory treatment. We are included in Wisconsin Energy's consolidated Federal income tax return. Wisconsin Energy allocates Federal tax expense or credits to us based on our separate tax computation. For further information on income taxes, see Note G.

Wisconsin Energy allocates the tax benefit of exercised stock options to us to the extent the option holder's payroll cost was incurred by us. We record the allocated tax benefit as an addition to paid in capital.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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: Our employees participate in the Wisconsin Energy stock-based compensation plan. The amounts reported represent the allocated costs related to options held by our employees.

Wisconsin Energy estimates the fair value of stock options using the binomial pricing model. 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 the grant date. Excess tax benefits are reported as a financing cash inflow. In addition, Wisconsin Energy reports unearned stock-based compensation associated with non-vested restricted stock and performance awards within other paid in capital in its Consolidated Statements of Common Equity. For a discussion of the impacts to our Consolidated Financial Statements, see Note H.

The fair value of each Wisconsin Energy option was calculated using a binomial option pricing model using the following weighted-average assumptions:

	2010	2009	2008
Risk-free interest rate	0.2% - 3.9%	0.3% - 2.5%	2.9% - 3.9%
Dividend yield	3.7%	3.0%	2.1%
Expected volatility	20.3%	25.9%	20.0%
Expected life (years)	5.9	6.2	6.2
Expected forfeiture rate	2.0%	2.0%	2.0%
Pro forma weighted-average fair value of stock options granted	\$6.72	\$8.01	\$9.39

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Amendments to Variable Interest Entity Consolidation Guidance: In June 2009, the Financial Accounting Standards Board issued new accounting guidance related to variable interest entity consolidation. The purpose of this guidance is to improve financial reporting by enterprises with variable interest entities. The new guidance is effective for all new and existing variable interest entities for fiscal years beginning after November 15, 2009. We adopted these provisions on January 1, 2010. This adoption did not have any impact on our financial condition, results of operations or cash flows. See Note F -- Variable Interest Entities for required disclosures.

C -- REGULATORY ASSETS AND LIABILITIES

Our primary regulator, the PSCW, considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed, or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon orders or correspondence with our regulators. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2010 and 2009, we had approximately \$12.2 million and \$12.4 million, respectively, of net regulatory assets that were not earning a return.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

	2010	2009
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	\$384.9	\$378.6
Deferred plant related -- capital leases	231.7	163.7
Escrowed electric transmission costs	138.0	157.8
Deferred unrecognized OPEB costs	50.6	77.9
Deferred income tax related	86.7	75.5
Other, net	164.1	209.6
Total regulatory assets	\$1,056.0	\$1,063.1
Regulatory Liabilities		
Deferred cost of removal obligations	\$564.2	\$497.5
Deferred Point Beach related	-	202.4
Deferred income tax related	33.1	49.7
Other, net	75.3	62.5
Total regulatory liabilities	\$672.6	\$812.1

Our rates allow us to recover and expense capital lease payments as they are due. We defer as a regulatory asset the difference between the capital lease expense recovered in rates and the expense that would result from the amortization of the leased asset and the imputed interest expense.

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

We have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of the pension and OPEB plans qualify as a regulatory asset.

We record deferred regulatory assets and liabilities representing the future expected impact of deferred taxes on utility revenues. For further information, see Note A.

Consistent with a generic order from, and past rate-making practices of, the PSCW, we defer as a regulatory asset costs associated with the remediation of former manufactured gas plant sites. As of December 31, 2010, we have recorded \$20.2 million of environmental costs associated with manufactured gas plant sites as a regulatory asset, including \$6.5 million of deferrals for actual remediation costs incurred and a \$13.7 million accrual for estimated future site remediation (see Note Q). In addition, we have deferred \$2.5 million of insurance recoveries associated with the environmental costs as regulatory liabilities. We amortize the deferred costs actually incurred and insurance recoveries over five years in accordance with PSCW rate-making treatment.

As of December 31, 2010, we have a regulatory liability of \$5.1 million for escrowed bad debt costs. The PSCW authorized escrow accounting for residential bad debt costs whereby we defer actual bad debt write-offs that exceed amounts allowed in rates.

D -- DIVESTITURES

Edgewater Generating Unit 5: During the fourth quarter of 2009, we reached a contingent agreement to sell our 25% interest in Edgewater Generating Unit 5 to WPL for our net book value, including working capital. In March 2010, the agreement became effective and we are in the process of receiving regulatory approvals. We received approval for the sale from FERC in June 2010, and from the PSCW in November 2010. We are currently working with the MPSC to obtain approval on terms that are acceptable to us. Assuming completion of the sale, we expect to realize proceeds of between \$40 million

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

and \$45 million depending on the working capital balances and our level of capital investment in the unit prior to the sale. The contractual deadline to complete the sale is June 30, 2011.

E -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2010 and 2009:

	2010	2009
	(Millions of Dollars)	
Balance as of January 1	\$52.6	\$52.3
Liabilities incurred	-	-
Liabilities settled	(2.5)	(2.6)
Accretion	2.9	2.9
Cash Flow Revisions	(2.2)	-
Balance as of December 31	<u>\$50.8</u>	<u>\$52.6</u>

F -- VARIABLE INTEREST ENTITIES

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

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

We have identified 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 three 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 12 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 \$364.3 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 2010, 2009 and 2008 were \$64.2 million, \$62.2 million and \$66.4 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

G -- INCOME TAXES

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

Income Taxes	2010	2009	2008
	(Millions of Dollars)		
Current tax expense (benefit)	\$95.2	\$25.4	(\$95.3)
Deferred income taxes, net	72.9	135.8	270.5
Investment tax credit, net	(3.3)	(3.5)	(5.9)
Total Income Tax Expense	<u>\$164.8</u>	<u>\$157.7</u>	<u>\$169.3</u>

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 and preferred dividend as a result of the following:

Income Tax Expense	2010		2009		2008	
	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
	(Millions of Dollars)					
Expected tax at statutory federal tax rates	\$167.6	35.0%	\$155.8	35.0%	\$157.3	35.0%
State income taxes net of federal tax benefit	24.5	5.1%	22.5	5.0%	23.5	5.2%
Domestic production activities deduction	(12.6)	(2.6%)	(8.3)	(1.9%)	(7.9)	(1.8%)
AFUDC - Equity	(11.3)	(2.4%)	(5.5)	(1.2%)	(2.6)	(0.6%)
Production tax credits - wind	(7.2)	(1.5%)	(7.1)	(1.6%)	(4.8)	(1.1%)
Investment tax credit restored	(3.3)	(0.7%)	(3.5)	(0.8%)	(5.9)	(1.3%)
Other, net	7.1	1.4%	3.8	0.8%	9.7	2.2%
Total Income Tax Expense	<u>\$164.8</u>	<u>34.3%</u>	<u>\$157.7</u>	<u>35.3%</u>	<u>\$169.3</u>	<u>37.6%</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

	2010	2009
	(Millions of Dollars)	
<u>Deferred Tax Assets</u>		
Current		
Deferred gain	\$ -	\$21.3
Employee benefits and compensation	11.0	10.7
Recoverable gas costs	0.9	0.6
Other	(0.3)	(1.2)
Total Current Deferred Tax Assets	<u>11.6</u>	<u>31.4</u>
Non-current		
Deferred revenues	305.9	270.8
Construction advances	115.5	111.9
Employee benefits and compensation	7.9	16.1
Emission allowances	2.6	4.0
Other	4.6	(17.4)
Total Non-Current Deferred Tax Assets	<u>436.5</u>	<u>385.4</u>
Total Deferred Tax Assets	<u>\$448.1</u>	<u>\$416.8</u>
	2010	2009
	(Millions of Dollars)	
<u>Deferred Tax Liabilities</u>		
Current		
Prepaid items	\$45.4	\$45.8
Uncollectible account expense	(15.8)	(4.0)
Total Current Deferred Tax Liabilities	<u>29.6</u>	<u>41.8</u>
Non-current		
Property-related	1,177.2	1,039.0
Employee benefits and compensation	(6.5)	-
Deferred transmission costs	53.1	63.2
Investment in transmission affiliate	98.2	80.1
Other	39.9	36.9
Total Non-current Deferred Tax Liabilities	<u>1,361.9</u>	<u>1,219.2</u>
Total Deferred Tax Liabilities	<u>\$1,391.5</u>	<u>\$1,261.0</u>
<u>Consolidated Balance Sheet Presentation</u>		
	2010	2009
Current Deferred Tax Asset (Liability)	(\$18.0)	(\$10.4)
Non-Current Deferred Tax Asset (Liability)	(\$925.4)	(\$833.8)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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:

	2010	2009
	(Millions of Dollars)	
Balance as of January 1	\$21.4	\$17.2
Additions based on tax positions related to the current year	0.8	0.9
Additions for tax positions of prior years	10.4	4.5
Reductions for tax positions of prior years	(2.5)	(1.2)
Reductions due to statute of limitations	-	-
Settlements during the period	(14.3)	-
Balance as of December 31	<u>\$15.8</u>	<u>\$21.4</u>

The amount of unrecognized tax benefits as of December 31, 2010 and 2009 excludes deferred tax assets related to uncertainty in income taxes of \$14.6 million and \$13.4 million, respectively. As of December 31, 2010 and 2009, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately \$1.3 million and \$8.1 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, 2010, 2009 and 2008, we recognized approximately \$3.6 million, \$1.4 million and \$1.7 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2010, 2009 and 2008, we recognized no penalties in the Consolidated Income Statements. We had approximately \$3.8 million and \$5.1 million of interest accrued in the Consolidated Balance Sheets as of December 31, 2010 and 2009, respectively.

Within the next 12 months, it is reasonably possible that our unrecognized tax benefits may decrease by approximately \$2.0 million as the result of payment on a state tax obligation for a prior year.

Our primary tax jurisdictions include Federal and the state of Wisconsin. Currently, the tax years of 2004 through 2010 are subject to Federal and Wisconsin examination.

H -- COMMON EQUITY

Share-Based Compensation Plans: Employees of Wisconsin Electric participate in a plan approved by Wisconsin Energy stockholders that provides a long-term incentive through equity interests in Wisconsin Energy to outside directors, selected officers and key employees of Wisconsin Energy and its subsidiaries. The plan provides for the granting of Wisconsin Energy stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in Wisconsin Energy 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 Wisconsin Energy stock options held by our employees during the period.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The following table summarizes recorded pre-tax share-based compensation expense and the related tax benefit for Wisconsin Energy share-based awards made to our employees during the years ended December 31:

	2010	2009	2008
	(Millions of Dollars)		
Stock options	\$7.0	\$9.9	\$11.3
Performance units	24.6	12.9	8.7
Restricted stock	0.8	0.3	0.3
Share-based compensation expense	<u>\$32.4</u>	<u>\$23.1</u>	<u>\$20.3</u>
Related Tax Benefit	<u>\$13.0</u>	<u>\$9.3</u>	<u>\$8.1</u>

Stock Options: The exercise price of a Wisconsin Energy 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 Wisconsin Energy stock options, see Note A.

The following is a summary of Wisconsin Energy stock option activity by our employees during 2010:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2010	8,237,428	\$38.95		
Granted	257,350	\$49.84		
Exercised	(2,472,471)	\$32.90		
Forfeited	(5,000)	\$45.70		
Outstanding as of December 31, 2010	<u>6,017,307</u>	\$41.90	5.9	\$102.1
Exercisable as of December 31, 2010	<u>3,518,982</u>	\$39.19	4.7	\$69.2

We expect that substantially all of the outstanding options as of December 31, 2010 will be exercised.

In January 2011, the Compensation Committee awarded 217,685 Wisconsin Energy non-qualified stock options at an exercise price of \$58.70 to our officers and key executives under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of Wisconsin Energy options exercised during the years ended December 31, 2010, 2009 and 2008 was \$53.2 million, \$5.9 million and \$6.9 million, respectively. Cash received by Wisconsin Energy from exercises of its options by our employees was \$81.1 million, \$8.2 million and \$8.0 million during the years ended December 31, 2010, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately \$21.0 million, \$2.5 million and \$2.3 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The following table summarizes information about Wisconsin Energy stock options held by our employees and outstanding as of December 31, 2010:

Range of Exercise Prices	Options Outstanding			Options Exercisable		
	Number of Options	Weighted-Average		Number of Options	Weighted-Average	
		Exercise Price	Remaining Contractual Life (Years)		Exercise Price	Remaining Contractual Life (Years)
\$20.39 to \$25.41	233,157	\$24.10	1.5	233,157	\$24.10	1.5
\$33.44 to \$39.48	2,056,842	\$35.90	4.1	2,056,842	\$35.90	4.1
\$42.22 to \$49.84	3,727,308	\$46.32	7.2	1,228,983	\$47.55	6.2
	<u>6,017,307</u>	<u>\$41.90</u>	<u>5.9</u>	<u>3,518,982</u>	<u>\$39.19</u>	<u>4.7</u>

The following table summarizes information about non-vested Wisconsin Energy options held by our employees during 2010:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of January 1, 2010	3,409,280	\$8.73
Granted	257,350	\$6.72
Vested	(1,163,305)	\$8.71
Forfeited	(5,000)	\$8.53
Non-Vested as of December 31, 2010	<u>2,498,325</u>	<u>\$8.53</u>

As of December 31, 2010, total compensation costs related to non-vested Wisconsin Energy stock options held by our employees and not yet recognized was approximately \$1.6 million, which is expected to be recognized over the next 15 months on a weighted-average basis.

Restricted Shares: The Compensation Committee has also approved grants of Wisconsin Energy restricted stock to certain of our key employees. The following restricted stock activity related to our employees occurred during 2010:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2010	57,999	
Granted	32,505	\$49.55
Released	(27,159)	\$23.51
Forfeited	(1,115)	\$49.55
Outstanding as of December 31, 2010	<u>62,230</u>	

Recipients of previously issued Wisconsin Energy 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 2011, the Compensation Committee awarded 25,845 restricted shares to our officers and other key employees as part of the long-term incentive program. These awards have a three-year vesting period, with, typically, one-third of the award vesting on each anniversary of the grant date. During the vesting period, restricted share recipients have voting rights and are entitled to dividends in the same manner as other shareholders.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Wisconsin Energy records the market value of the restricted stock awards on the date of grant. We then amortize our share of allocated expense over the vesting period of the awards. The intrinsic value of Wisconsin Energy restricted stock vesting and held by our employees was \$1.6 million, \$0.4 million and \$1.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was \$0.6 million, \$0.2 million and \$0.3 million, respectively.

As of December 31, 2010, total compensation cost related to our share of Wisconsin Energy restricted stock not yet recognized was approximately \$1.4 million, which is expected to be recognized over the next 26 months on a weighted-average basis.

Performance Units: In January 2010, 2009 and 2008, the Compensation Committee awarded 260,310, 309,310 and 124,175 Wisconsin Energy performance units, respectively, to our officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units which will be awarded is dependent upon the achievement of certain financial performance of Wisconsin Energy's common stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance award. All grants are settled in cash. We are accruing our share of compensation costs over the three-year period based on our estimate of the final expected value of the award. Performance units earned as of December 31, 2010, 2009 and 2008 had a total intrinsic value of \$12.1 million, \$9.3 million and \$7.9 million, respectively. The awards were subsequently distributed to our officers and key employees in January 2011, 2010 and 2009. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately \$4.2 million, \$3.2 million and \$2.9 million, respectively. As of December 31, 2010, total compensation cost related to performance units not yet recognized was approximately \$21.8 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

In January 2011, the Compensation Committee awarded 206,995 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Equity Contribution: Our capitalization reflects the impact of \$100.0 million equity contributions from Wisconsin Energy during 2010 and 2009.

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

The January 2010 PSCW rate order requires us to maintain a capital structure that differs from GAAP as it reflects regulatory adjustments. We are required to maintain a common equity ratio range of between 48.5% and 53.5%. We must obtain PSCW approval to pay dividends above the test year levels that would cause us to fall below the authorized level of common equity.

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

See Note J for a discussion of certain financial covenants related to our bank back-up credit facility.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

I -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2010, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2011	\$ -
2012	-
2013	300.0
2014	300.0
2015	250.0
Thereafter	1,137.0
Total	<u>\$1,987.0</u>

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

During 2009, we issued \$250 million of debentures under an existing \$800 million shelf registration statement filed with the SEC in August 2007. The net proceeds were used to repay short-term debt and for other general corporate purposes.

We are the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of \$147 million. In August 2009, we terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. We issued commercial paper to fund the purchase of the bonds. As of December 31, 2010 and 2009, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by us. Depending on market conditions and other factors, we may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Obligations Under Capital Leases

We are the obligor under a power purchase contract with an unaffiliated third party and we lease power plants from We Power under Wisconsin Energy's PTF strategy. Under capital lease accounting, we have recorded the leased plants and corresponding obligations under the capital leases on our Consolidated Balance Sheets. We treat these agreements as operating leases for rate-making purposes. We record our minimum lease payments under the power purchase contract as purchased power expense on the Consolidated Income Statements. We record the lease payments under our PTF leases as rent expense in other operation and maintenance in the Consolidated Income Statements. 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 leases in Note C).

Power Purchase Commitment: In 1997, we 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, we may, at our 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 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.

PWGS: We are leasing PWGS 1 and PWGS 2, two 545 MW natural gas-fired generation units which were placed in service in July 2005 and May 2008, respectively, from We Power under PSCW approved leases. We recorded the leased plants and corresponding obligations for PWGS 1 and PWGS 2 at the estimated fair value of \$338.7 million and \$331.1 million, respectively. We are amortizing the leased plants on a straight-line basis over the original 25-year term of the leases. The lease payments are expected to be recovered through our rates, as supported by the 2001 leased generation law. Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

approximately \$126.6 million in the year 2021 for PWGS 1 and to approximately \$127.3 million in the year 2024 for PWGS 2, at which time the regulatory assets will be reduced to zero over the remaining lives of the contracts. The total obligation under the capital leases for PWGS 1 and PWGS 2 was \$326.2 million and \$327.2 million, respectively, as of December 31, 2010 and will decrease to zero over the remaining lives of the contracts.

Oak Creek Expansion: As of December 31, 2010, we are leasing OC 1 which includes common facilities which are also utilized by our Oak Creek Units 5-8 from We Power under PSCW approved leases. We are amortizing the leased plant on a straight-line basis over the 30-year term of the lease. The common coal handling system was placed in service in November 2007 and the water intake system was placed in service in January 2009. OC 1 and the remaining common facilities were placed in service in February 2010. We have recorded the leased plant and a corresponding capital lease obligation at the estimated fair value of \$1,279.8 million. The lease payments are expected to be recovered through our rates, as supported by the 2001 leased generation law. The total obligation under the capital lease was \$1,287.3 million as of December 31, 2010, and will decrease to zero over the remaining life of the contract.

We paid the following lease payments during 2010, 2009 and 2008:

	2010	2009	2008
	(Millions of Dollars)		
Long-term power purchase commitment	\$30.2	\$29.1	\$28.1
PWGS	97.4	97.4	78.0
Oak Creek Expansion	178.6	41.6	24.2
Total	\$306.2	\$168.1	\$130.3

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The following table summarizes our capitalized leased facilities as of December 31:

Capital Lease Assets	2010	2009
	(Millions of Dollars)	
Long-term Power Purchase Commitment		
Under capital lease	\$140.3	\$140.3
Accumulated amortization	(75.5)	(69.8)
Total Long-term Power Purchase Commitment	<u>\$64.8</u>	<u>\$70.5</u>
PWGS		
Under capital lease	\$670.3	\$669.8
Accumulated amortization	(108.2)	(81.4)
Total PWGS	<u>\$562.1</u>	<u>\$588.4</u>
Oak Creek Expansion		
Under capital lease	\$1,279.8	\$316.4
Accumulated amortization	(56.0)	(15.7)
Total Oak Creek	<u>\$1,223.8</u>	<u>\$300.7</u>
Total Leased Facilities	<u>\$1,850.7</u>	<u>\$959.6</u>

Future minimum lease payments under our capital leases and the present value of our net minimum lease payments as of December 31, 2010 are as follows:

Capital Lease Obligations	Power Purchase Commitment	PWGS	Oak Creek Expansion	Total
	(Millions of Dollars)			
2011	\$37.5	\$97.5	\$179.2	\$314.2
2012	38.9	97.5	179.2	315.6
2013	40.4	97.5	179.2	317.1
2014	41.9	97.5	179.2	318.6
2015	43.5	97.5	197.7	338.7
Thereafter	130.6	1,556.3	4,788.8	6,475.7
Total Minimum Lease Payments	<u>332.8</u>	<u>2,043.8</u>	<u>5,703.3</u>	<u>8,079.9</u>
Less: Estimated Executory Costs	(81.2)	-	-	(81.2)
Net Minimum Lease Payments	<u>251.6</u>	<u>2,043.8</u>	<u>5,703.3</u>	<u>7,998.7</u>
Less: Interest	(109.7)	(1,390.4)	(4,416.0)	(5,916.1)
Present Value of Net				
Minimum Lease Payments	141.9	653.4	1,287.3	2,082.6
Less: Due Currently	(9.5)	(5.6)	(6.7)	(21.8)
Total Capital Lease Obligations	<u>\$132.4</u>	<u>\$647.8</u>	<u>\$1,280.6</u>	<u>\$2,060.8</u>

We recorded an increase of approximately \$1.0 billion to our capital lease obligations in connection with OC 1 being placed in service on February 2, 2010 and an increase of approximately \$650 million in connection with OC 2 being placed in service in January 2011. See Note S -- Subsequent Events for additional information.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)**J -- SHORT-TERM DEBT**

Our commercial paper balance and the corresponding weighted-average interest rate as of December 31 are shown in the following table:

	2010		2009	
	Balance	Interest Rate	Balance	Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial Paper	\$210.5	0.25%	\$92.0	0.19%

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

	2010	2009
	(Millions of Dollars, except for percentages)	
Maximum Commercial Paper Outstanding	\$268.0	\$437.5
Average Commercial Paper Outstanding	\$93.2	\$248.8
Weighted-Average Interest Rate	0.26%	0.27%

In December 2010, we entered into a new bank back-up credit facility to maintain short-term credit liquidity which, among other terms, requires us to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 65%.

As of December 31, 2010, we had approximately \$496.6 million of available, undrawn lines under our bank back-up credit facility. Our bank back-up credit facility expires in December 2013. As of December 31, 2010, we had approximately \$210.5 million of commercial paper outstanding that was supported by the available lines of credit, and our subsidiary had a \$27.6 million note payable to Wisconsin Energy with a weighted-average interest rate of 5.73%.

Our bank back-up credit facility contains customary covenants, including certain limitations on our ability to sell assets. The credit facility also contains 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.

As of December 31, 2010, we were in compliance with all financial covenants.

K -- 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. 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, 2010, we recognized \$11.0 million in regulatory assets and \$13.7 million in regulatory liabilities related to derivatives in comparison to \$11.6 million in regulatory assets and \$9.3 million in regulatory liabilities as of December 31, 2009.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

We record our current derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative assets of \$0.7 million is recorded in Other deferred charges and other assets, and the long-term portion of our derivative liabilities of \$0.2 million is recorded in Other deferred credits and other liabilities. Our Consolidated Balance Sheets as of December 31, 2010 and 2009 include:

	December 31, 2010		December 31, 2009	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	\$0.9	\$6.3	\$1.2	\$6.6
Fuel Oil	4.4	-	0.6	-
FTRs	5.9	-	5.8	-
Coal	2.9	-	2.1	-
Total	<u>\$14.1</u>	<u>\$6.3</u>	<u>\$9.7</u>	<u>\$6.6</u>

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, 2010 and 2009 were as follows:

	December 31, 2010		December 31, 2009	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	37.8 million Dth	(\$23.3)	45.2 million Dth	(\$70.9)
Power	234,720 MWh	(0.5)	23,520 MWh	(0.5)
Fuel Oil	8.1 million gallons	(0.5)	6.8 million gallons	(2.5)
FTRs	25,234 MW	19.2	27,262 MW	12.9
Total		<u>(\$5.1)</u>		<u>(\$61.0)</u>

As of December 31, 2010 and 2009, we posted collateral of \$4.2 million and \$6.6 million, respectively, in our margin accounts. These amounts are recorded on the balance sheet in Other current assets.

L -- 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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, 2010			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$8.3	\$ -	\$ -	\$8.3
Derivatives	4.5	3.7	5.9	14.1
Total	<u>\$12.8</u>	<u>\$3.7</u>	<u>\$5.9</u>	<u>\$22.4</u>
Liabilities:				
Derivatives	<u>\$3.0</u>	<u>\$3.3</u>	<u>\$ -</u>	<u>\$6.3</u>
Total	<u>\$3.0</u>	<u>\$3.3</u>	<u>\$ -</u>	<u>\$6.3</u>
Recurring Fair Value Measures	As of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$194.5	\$ -	\$ -	\$194.5
Derivatives	0.6	3.3	5.8	9.7
Total	<u>\$195.1</u>	<u>\$3.3</u>	<u>\$5.8</u>	<u>\$204.2</u>
Liabilities:				
Derivatives	<u>\$4.2</u>	<u>\$2.4</u>	<u>\$ -</u>	<u>\$6.6</u>
Total	<u>\$4.2</u>	<u>\$2.4</u>	<u>\$ -</u>	<u>\$6.6</u>

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of Point Beach. 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

The following tables summarize the fair value of derivatives classified as Level 3 in the fair value hierarchy:

	2010	2009
	(Millions of Dollars)	
Balance as of January 1	\$5.8	\$8.7
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	0.1	(2.9)
Transfers in and/or out of Level 3	-	-
Balance as of December 31	<u>\$5.9</u>	<u>\$5.8</u>
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 K -- 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 are as follows:

Financial Instruments	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	\$30.4	\$23.5	\$30.4	\$20.2
Long-term debt including current portion	\$1,987.0	\$2,158.7	\$1,987.1	\$2,088.2

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 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.

M -- BENEFITS

Pensions and Other Post-retirement Benefits: We participate in Wisconsin Energy's 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 participate in Wisconsin Energy's OPEB plans that cover 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The assets, obligations and the components of our pension costs are allocated by Wisconsin Energy's actuary to each of the participating companies as if each participating company had its own plan. The disclosures below are based on an allocation to us of the amounts for Wisconsin Energy's pension plans.

Wisconsin Energy uses a year-end measurement date to measure the funded status of all of the 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 the pension and OPEB plans qualify as a regulatory asset.

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

	Pension		OPEB	
	2010	2009	2010	2009
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	\$992.6	\$967.0	\$304.1	\$254.6
Service cost	22.1	21.4	10.6	8.2
Interest cost	58.9	61.9	17.4	16.5
Participants' contributions	-	-	6.1	6.2
Plan amendments	-	0.2	-	(9.3)
Actuarial loss (gain)	52.7	42.2	(24.6)	43.5
Gross benefits paid	(70.3)	(100.1)	(17.3)	(16.5)
Federal subsidy on benefits paid	N/A	N/A	0.8	0.9
Benefit Obligation at December 31	<u>\$1,056.0</u>	<u>\$992.6</u>	<u>\$297.1</u>	<u>\$304.1</u>
Change in Plan Assets				
Fair Value at January 1	\$793.7	\$510.7	\$129.3	\$97.0
Actual earnings on plan assets	84.7	113.9	15.1	20.8
Employer contributions	5.6	269.2	2.7	21.8
Participants' contributions	-	-	6.1	6.2
Gross benefits paid	(70.3)	(100.1)	(17.3)	(16.5)
Fair Value at December 31	<u>\$813.7</u>	<u>\$793.7</u>	<u>\$135.9</u>	<u>\$129.3</u>
Net Liability	<u>\$242.3</u>	<u>\$198.9</u>	<u>\$161.2</u>	<u>\$174.8</u>

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

	Pension		OPEB	
	2010	2009	2010	2009
	(Millions of Dollars)			
Other deferred charges	\$ -	\$ -	\$0.2	\$0.5
Other long-term liabilities	242.3	198.9	161.4	175.3
Net liability	<u>\$242.3</u>	<u>\$198.9</u>	<u>\$161.2</u>	<u>\$174.8</u>

The accumulated benefit obligation for all the defined benefit plans was \$1,055.7 million and \$978.9 million as of December 31, 2010 and 2009, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

	Pension		OPEB	
	2010	2009	2010	2009
	(Millions of Dollars)			
Net actuarial loss	\$364.6	\$355.9	\$65.9	\$104.7
Prior service costs (credits)	15.7	17.8	(7.4)	(19.2)
Transition obligation	-	-	0.7	1.0
Total	<u>\$380.3</u>	<u>\$373.7</u>	<u>\$59.2</u>	<u>\$86.5</u>

The following table shows the estimated amounts that will be amortized as a component of net periodic benefit costs during 2011:

	Pension	OPEB
	(Millions of Dollars)	
Net actuarial loss	\$23.2	\$4.3
Prior service costs (credits)	2.2	(1.9)
Transition obligation	-	0.3
Total	<u>\$25.4</u>	<u>\$2.7</u>

Information for the pension plan, which has an accumulated benefit obligation in excess of the fair value of assets as of December 31 is as follows:

	2010	2009
	(Millions of Dollars)	
Projected benefit obligation	\$1,056.0	\$992.6
Accumulated benefit obligation	\$1,055.7	\$978.9
Fair value of plan assets	\$813.7	\$793.7

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

	Pension			OPEB		
	2010	2009	2008	2010	2009	2008
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	\$22.1	\$21.4	\$17.1	\$10.6	\$8.2	\$9.8
Interest cost	59.0	61.9	60.4	17.4	16.5	15.9
Expected return on plan assets	(59.5)	(73.0)	(60.7)	(9.1)	(8.9)	(10.9)
Amortization of:						
Transition obligation	-	-	-	0.3	0.3	0.3
Prior service cost (credit)	2.1	2.1	2.4	(11.9)	(12.6)	(12.6)
Actuarial loss	18.8	12.8	10.1	8.2	5.5	4.6
Net Periodic Benefit Cost	<u>\$42.5</u>	<u>\$25.2</u>	<u>\$29.3</u>	<u>\$15.5</u>	<u>\$9.0</u>	<u>\$7.1</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

	Pension			OPEB		
	2010	2009	2008	2010	2009	2008
<u>Weighted-Average assumptions used to determine benefit obligations as of Dec. 31</u>						
Discount rate	5.60%	6.05%	6.50%	5.70%	5.75%	6.50%
Rate of compensation increase	4.00%	4.00%	4.00%	N/A	N/A	N/A
<u>Weighted-Average assumptions used to determine net cost for year ended Dec. 31</u>						
Discount rate	6.05%	6.50%	6.05%	5.75%	6.50%	6.10%
Expected return on plan assets	7.25%	8.25%	8.50%	7.50%	8.25%	8.50%
Rate of compensation increase	4.00%	4.00%	4.50% to 5.00%	N/A	N/A	N/A
<u>Assumed health care cost trend rates as of Dec. 31</u>						
Health care cost trend rate assumed for next year (Pre 65 / Post 65)				7.5%/16%	7.5%/20%	7.5%/9%
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)				2015/2016	2015/2016	2014

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.5%, respectively, in 2010. The expected long-term rate of return for all plan assets was 8.25% in 2009 and 8.5% in 2008. Wisconsin Energy consults with its investment advisors on an annual basis to help 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:

Effect on	1% Increase	1% Decrease
	(Millions of Dollars)	
Post-retirement benefit obligation	\$30.6	(\$25.6)
Total of service and interest cost components	\$4.0	(\$3.3)

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

Plan Assets: Current pension trust assets and amounts which are expected to be contributed to the trusts in the future will 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The following table summarizes the fair value of our share of plan assets as of December 31, 2010 by asset category within the fair value hierarchy (for further level information, see Note L):

Asset Category - Pension	As of December 31, 2010			Total
	Level 1	Level 2	Level 3	
	(Millions of Dollars)			
Cash and Cash Equivalents	\$16.2	\$ -	\$ -	\$16.2
Equities:				
U.S. Equity	166.8	190.1	-	356.9
International Equity	62.3	16.6	-	78.9
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	38.2	277.6	-	315.8
International Bonds	24.4	21.5	-	45.9
Total	<u>\$307.9</u>	<u>\$505.8</u>	<u>\$ -</u>	<u>\$813.7</u>

Asset Category - Pension	As of December 31, 2009			Total
	Level 1	Level 2	Level 3	
	(Millions of Dollars)			
Cash and Cash Equivalents	\$8.3	\$ -	\$ -	\$8.3
Equities:				
U.S. Equity	142.0	167.0	-	309.0
International Equity	45.3	26.1	-	71.4
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	347.2	-	-	347.2
International Bonds	33.7	-	-	33.7
Commercial Paper (b)	24.1	-	-	24.1
Total	<u>\$600.6</u>	<u>\$193.1</u>	<u>\$ -</u>	<u>\$793.7</u>

- (a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.
- (b) This category represents investment in commercial paper issued by Wisconsin Energy. The plan did not hold Wisconsin Energy commercial paper as of December 31, 2010.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The following table summarizes the fair value of our share of OPEB plan assets as of December 31, 2010 by asset category within the fair value hierarchy:

Asset Category - OPEB	As of December 31, 2010			Total
	Level 1	Level 2	Level 3	
	(Millions of Dollars)			
Cash and Cash Equivalents	\$0.9	\$ -	\$ -	\$0.9
Equities:				
U.S. Equity	26.1	50.2	-	76.3
International Equity	3.3	0.9	-	4.2
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	13.6	37.3	-	50.9
International Bonds	1.3	2.3	-	3.6
Total	<u>\$45.2</u>	<u>\$90.7</u>	<u>\$ -</u>	<u>\$135.9</u>

Asset Category - OPEB	As of December 31, 2009			Total
	Level 1	Level 2	Level 3	
	(Millions of Dollars)			
Cash and Cash Equivalents	\$0.5	\$ -	\$ -	\$0.5
Equities:				
U.S. Equity	23.9	46.5	-	70.4
International Equity	2.2	1.3	-	3.5
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	52.1	-	-	52.1
International Bonds	1.7	-	-	1.7
Commercial Paper (b)	1.1	-	-	1.1
Total	<u>\$81.5</u>	<u>\$47.8</u>	<u>\$ -</u>	<u>\$129.3</u>

- (a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.
- (b) This category represents investment in commercial paper issued by Wisconsin Energy. The plan did not hold Wisconsin Energy's commercial paper as of December 31, 2010.

In January 2009, the committee that oversees the investment of the pension assets authorized the Trustee of Wisconsin Energy's pension plan to invest in the commercial paper of Wisconsin Energy. As of December 31, 2010 and 2009, the Pension Trust and OPEB plan assets included our share of approximately zero and \$25.2 million of commercial paper issued by Wisconsin Energy, which represents less than 10% of total assets of the plan.

Cash Flows:

Employer Contributions	Pension		OPEB
	Qualified	Non-Qualified	
	(Millions of Dollars)		
2008	\$ 37.9	\$5.7	\$11.0
2009	\$264.6	\$4.6	\$21.8
2010	\$ -	\$5.6	\$2.7

In January 2011, we contributed \$99.1 million to the qualified pension plan and rebalanced the investment portfolio to the targeted asset allocation levels. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

The entire contribution to the OPEB plans during 2010 was discretionary as the plans are not subject to any minimum regulatory funding requirements.

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

Year	Pension	Gross OPEB (Millions of Dollars)	Expected Medicare Part D Subsidy
2011	\$85.3	\$15.3	(\$0.4)
2012	\$86.6	\$15.0	-
2013	\$90.7	\$16.4	-
2014	\$94.1	\$17.5	-
2015	\$89.0	\$18.7	-
2016-2020	\$449.2	\$107.4	-

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 \$12.5 million during 2010 and 2009 and \$13.3 million during 2008.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was \$10.7 million as of December 31, 2010.

N -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties. As of December 31, 2010, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding (Millions of Dollars)	Liability Recorded
Guarantees	\$2.8	\$0.1	\$ -
Letters of Credit	\$1.5	\$1.0	\$ -

We are subject to the potential retrospective premiums that could be assessed under our insurance program.

O -- SEGMENT REPORTING

We are a subsidiary of Wisconsin Energy and have organized our operating segments according to how we are currently regulated. Our reportable operating segments include electric, natural gas and steam utility segments. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our electric utility 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 is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas in three service areas in southeastern, east central and northern Wisconsin. Our steam utility produces, distributes and sells steam to space heating and processing customers in the Milwaukee, Wisconsin area.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Summarized financial information concerning our operating segments for the years ended December 31, 2010, 2009 and 2008 is shown in the following table:

<u>Year Ended</u>	<u>Operating Segments</u>			<u>Other (a)</u>	<u>Total</u>
	<u>Electric</u>	<u>Gas</u>	<u>Steam</u>		
	(Millions of Dollars)				
<u>December 31, 2010</u>					
Operating Revenues (b)	\$2,936.3	\$481.6	\$38.8	\$ -	\$3,456.7
Depreciation, Decommissioning and Amortization	\$187.0	\$25.9	\$3.3	\$ -	\$216.2
Operating Income (c)	\$448.1	\$38.9	\$2.2	\$ -	\$489.2
Equity in Earnings of Transmission Affiliate	\$52.7	\$ -	\$ -	\$ -	\$52.7
Capital Expenditures	\$574.9	\$38.8	\$2.5	\$1.1	\$617.3
Total Assets (d)	\$9,356.8	\$638.1	\$65.3	\$110.5	\$10,170.7
<u>December 31, 2009</u>					
Operating Revenues (b)	\$2,685.0	\$564.2	\$39.1	\$ -	\$3,288.3
Depreciation, Decommissioning and Amortization	\$225.7	\$35.5	\$3.9	\$ -	\$265.1
Operating Income (c)	\$409.0	\$53.4	\$6.5	\$ -	\$468.9
Equity in Earnings of Transmission Affiliate	\$51.9	\$ -	\$ -	\$ -	\$51.9
Capital Expenditures	\$448.0	\$30.4	\$2.6	\$0.1	\$481.1
Total Assets (d)	\$8,019.4	\$668.7	\$65.8	\$117.3	\$8,871.2
<u>December 31, 2008</u>					
Operating Revenues (b)	\$2,660.6	\$709.2	\$40.3	\$ -	\$3,410.1
Depreciation, Decommissioning and Amortization	\$219.8	\$32.5	\$3.7	\$ -	\$256.0
Operating Income (c)	\$413.2	\$61.6	\$7.1	\$ -	\$481.9
Equity in Earnings of Transmission Affiliate	\$45.4	\$ -	\$ -	\$ -	\$45.4
Capital Expenditures	\$459.0	\$59.1	\$5.6	\$ -	\$523.7
Total Assets (d)	\$7,810.5	\$779.8	\$67.7	\$117.4	\$8,775.4

- (a) Other includes primarily non-utility property and investments, materials and supplies, deferred charges and other corporate items.
- (b) We account for intersegment revenues at a tariff rate established by the PSCW. Intersegment revenues were not material.
- (c) We evaluate operating income to manage our utility business. Equity in Earnings of Transmission Affiliate, Interest Expense and Income Taxes are not included in segment operating income.
- (d) Common utility plant is allocated to electric, gas and steam utility operations to determine segment assets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

P -- RELATED PARTIES

We provide to and receive from certain of our Wisconsin Energy affiliates managerial, financial, accounting, legal, data processing and other services in accordance with service agreements approved by the PSCW. In addition, we make lease payments to We Power for PWGS 1, PWGS 2 and OC 1, including the common facilities. OC 2 was placed in service on January 12, 2011. We also receive and/or provide certain services to other associated companies in which we have, or Wisconsin Energy has, an equity investment.

American Transmission Company LLC: As of December 31, 2010, we had a 23.0% 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 Wisconsin Energy's PTF strategy. ATC reimburses us for these costs when new generation is placed into service. As of December 31, 2010 and 2009, we had a receivable of \$3.8 million and \$1.1 million, respectively, for these items.

Summary financial information as of December 31 from the financial statements of ATC is as follows:

	2010	2009	2008
	(Millions of Dollars)		
Operating Revenues	\$556.7	\$521.5	\$466.6
Operating Income	\$305.6	\$291.2	\$257.6
Net Income	\$219.7	\$213.4	\$188.0
Current Assets	\$59.9	\$51.1	\$50.8
Non-Current Assets	\$2,888.4	\$2,767.3	\$2,480.0
Current Liabilities	\$428.4	\$285.5	\$252.0
Non-Current Liabilities	\$1,260.0	\$1,336.5	\$1,229.6

We provided and received services from the following associated companies during 2010, 2009 and 2008:

Company	2010	2009	2008
	(Millions of Dollars)		
<u>Affiliate</u>			
Net Services Provided			
-We Power (excluding lease payments)	\$0.6	\$1.2	\$1.3
-Wisconsin Gas	\$64.8	\$58.2	\$51.3
-Other	\$0.9	\$1.1	\$1.7
Net Services Received			
-We Power (lease payments)	\$367.8	\$347.0	\$312.2
-Wisconsin Energy	\$26.5	\$15.8	\$12.6
<u>Equity Investee</u>			
Services Provided			
-ATC	\$16.9	\$22.3	\$20.0
Services Received			
-ATC	\$220.8	\$196.0	\$194.4

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

As of December 31, 2010 and 2009, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2010	2009
	(Millions of Dollars)	
Services Provided		
-ATC	\$0.9	\$1.1
Services Received		
-ATC	\$18.5	\$16.3

Q -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2011 capital expenditures. During 2011, we estimate that total capital expenditures will be approximately \$841.7 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)
2011	\$22.8
2012	16.3
2013	6.5
2014	3.9
2015	4.0
Thereafter	32.7
Total	\$86.2

Divested Assets: Pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets.

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 our manufactured gas plant sites and related disposal sites, as well as our coal combustion product disposal/landfill sites, 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 we or a predecessor company historically owned or operated a manufactured gas plant. We have substantially completed planned remediation activities at some of those sites and certain other sites are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 \$10 million to \$25 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, 2010, we have established reserves of \$13.7 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including us, 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: We aggressively seek environmentally acceptable, beneficial uses for our 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 we have 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 2010, 2009 and 2008, we incurred \$0.4 million, \$0.3 million and \$1.3 million, respectively, in landfill remediation expenses. As of December 31, 2010, we have no reserves established related to coal combustion product landfill sites.

EPA - Consent Decree: In April 2003, we reached a Consent Decree with the EPA in which we agreed to significantly reduce air emissions from our 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 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, 2010, we have spent approximately \$901 million 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 estimated to be \$1.2 billion over the 10 year period ending 2013.

Cash Balance Pension Plan: On June 30, 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. Counsel representing the plaintiff is attempting to seek class certification for other similarly situated plaintiffs. The complaint alleges 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 are 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. On September 6, 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy Corporation as a defendant. The plaintiff has not specified the amount of relief he is seeking. An adverse outcome of this lawsuit could have an adverse effect on Plan funding and expense, and our results of operations. Although we are currently unable to predict the final outcome or impact of this litigation, we are aware that courts in two similar lawsuits filed in Wisconsin found that the interest crediting rates applied by pension plans involved in those cases were not in compliance with ERISA.

R -- SUPPLEMENTAL CASH FLOW INFORMATION

During the year ended December 31, 2010, we paid \$99.7 million in interest, net of amounts capitalized, and \$112.0 million in income taxes, net of refunds. During the year ended December 31, 2009, we paid \$98.5 million in interest, net of amounts capitalized, and \$7.7 million in income taxes, net of refunds. During the year ended December 31, 2008, we paid \$78.6 million in interest, net of amounts capitalized, and \$0.6 million in income taxes, net of refunds.

As of December 31, 2010, 2009 and 2008, the amount of accounts payable related to capital expenditures was \$16.8 million, \$8.1 million and \$22.3 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)**S -- SUBSEQUENT EVENTS**

On January 12, 2011, OC 2 was placed into service. We now have care, custody and control of OC 2 and will operate and maintain it over the 30 year life of the lease. As a result of the commercial operation of OC 2, in January 2011, we recorded an additional capital lease asset and capital lease obligation related to the Oak Creek expansion totaling approximately \$650 million. We also expect that the additional lease payments for the Oak Creek expansion will total approximately \$2.9 billion over the next 30 years.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**To the Board of Directors and Stockholders of Wisconsin Electric Power Company:**

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Electric Power Company and subsidiary (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15(a)(2). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Electric Power Company and subsidiary as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 25, 2011

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES**Disclosure Controls and Procedures**

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

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 Electric Power Company's 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 Electric Power Company's internal control over financial reporting was effective as of December 31, 2010.

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.

This annual report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to rules of the SEC that permit the Company to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III**ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANT**

The information under "Election of Directors", "Section 16(a) Beneficial Ownership Reporting Compliance", "Corporate Governance -- Frequently Asked Questions: What is the process used to identify director nominees and how do I recommend a nominee to WEC's Corporate Governance Committee?", "Corporate Governance -- Frequently Asked Questions: Are the Audit and Oversight and Compensation Committees comprised solely of independent directors?", "Corporate Governance -- Frequently Asked Questions: Are all the members of the Audit Committee financially literate and does the committee have an 'audit committee financial expert'?", "Corporate Governance -- Frequently Asked Questions: Does the Board have a nominating committee?" and "Committees of the Board of Directors -- Audit and Oversight" in our Definitive Information Statement on Schedule 14C to be filed with the SEC for our Annual Meeting of Stockholders to be held April 28, 2011 (the "2011 Annual Meeting Information Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" in Part I of this report.

Wisconsin Energy has adopted a written code of ethics, referred to as its Code of Business Conduct. We are a subsidiary of Wisconsin Energy, and as such, all of our directors, executive officers and employees, including our principal executive officer, principal financial officer and principal accounting officer, have a responsibility to comply with Wisconsin Energy's Code of Business Conduct. Wisconsin Energy has posted its Code of Business Conduct in the "Governance" section on its website, www.wisconsinenergy.com. Wisconsin Energy has not provided any waiver to the Code for any director, executive officer or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on Wisconsin Energy's website or in a current report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis", "Executive Officers' Compensation", "Director Compensation", "Committees of the Board of Directors -- Compensation", "Compensation Committee Report", "Risk Analysis of Compensation Policies and Practices" and "Certain Relationships and Related Transactions -- Compensation Committee Interlocks and Insider Participation" in the 2011 Annual Meeting Information Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

All of our Common Stock is owned by our parent company, Wisconsin Energy Corporation, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201. Our directors, director nominees and executive officers do not own any of our voting securities. The information concerning their beneficial ownership in Wisconsin Energy common stock set forth under "Stock Ownership of Directors, Nominees and Executive Officers" in the 2011 Annual Meeting Information Statement is incorporated herein by reference.

We do not have any equity compensation plans under which our equity securities may be issued. Our directors, officers and certain employees participate in the compensation plans of Wisconsin Energy Corporation.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information under "Corporate Governance -- Frequently Asked Questions: Who are the independent directors?", "Corporate Governance -- Frequently Asked Questions: What are the Board's standards of independence?", "Corporate Governance -- Frequently Asked Questions: Are the Audit and Oversight and Compensation Committees comprised solely of independent directors?", "Corporate Governance -- Frequently Asked Questions: Does the Company have policies and procedures in place to review and approve related party transactions?" and "Certain Relationships and Related Transactions" in the 2011 Annual Meeting Information Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of Wisconsin Energy's Corporate Governance Guidelines, which can be found on its website, www.wisconsinenergy.com.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Independent Auditors' Fees and Services" in the 2011 Annual Meeting Information Statement is incorporated herein by reference.

PART IV**ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES****(a) 1. FINANCIAL STATEMENTS AND REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM INCLUDED IN PART II OF THIS REPORT**

<u>Description</u>	<u>Page in 10-K</u>
Consolidated Income Statements for the three years ended December 31, 2010.	67
Consolidated Balance Sheets at December 31, 2010 and 2009.	68
Consolidated Statements of Cash Flows for the three years ended December 31, 2010.	70
Consolidated Statements of Capitalization at December 31, 2010 and 2009.	71
Consolidated Statements of Common Equity for the three years ended December 31, 2010.	72
Notes to Consolidated Financial Statements.	73
Report of Independent Registered Public Accounting Firm.	103

2. FINANCIAL STATEMENT SCHEDULES INCLUDED IN PART IV OF THIS REPORT

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2010.

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. EXHIBITS AND EXHIBIT INDEX

See the Exhibit Index included as the last part of this report, which is incorporated herein by reference. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report is identified in the Exhibit Index by two asterisks (**) following the description of the exhibit.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts	Balance at Beginning of the Period	Expense	Deferral	Net Write-offs	Balance at End of the Period
			(Millions of Dollars)		
December 31, 2010	\$31.5	\$46.9	(\$14.0)	(\$30.2)	\$34.2
December 31, 2009	\$27.2	\$29.0	\$8.6	(\$33.3)	\$31.5
December 31, 2008	\$21.9	\$28.4	\$5.2	(\$28.3)	\$27.2

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WISCONSIN ELECTRIC POWER COMPANY

Date: February 25, 2011

By /s/GALE E. KLAPPA
Gale E. Klappa, Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>/s/GALE E. KLAPPA</u> Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer and Director -- Principal Executive Officer	February 25, 2011
<u>/s/ALLEN L. LEVERETT</u> Allen L. Leverett, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	February 25, 2011
<u>/s/STEPHEN P. DICKSON</u> Stephen P. Dickson, Vice President and Controller -- Principal Accounting Officer	February 25, 2011
<u>/s/JOHN F. BERGSTROM</u> John F. Bergstrom, Director	February 25, 2011
<u>/s/BARBARA L. BOWLES</u> Barbara L. Bowles, Director	February 25, 2011
<u>/s/PATRICIA W. CHADWICK</u> Patricia W. Chadwick, Director	February 25, 2011
<u>/s/ROBERT A. CORNOG</u> Robert A. Cornog, Director	February 25, 2011
<u>/s/CURT S. CULVER</u> Curt S. Culver, Director	February 25, 2011
<u>/s/THOMAS J. FISCHER</u> Thomas J. Fischer, Director	February 25, 2011
<u>/s/ULICE PAYNE, JR.</u> Ulice Payne, Jr., Director	February 25, 2011
<u>/s/FREDERICK P. STRATTON, JR.</u> Frederick P. Stratton, Jr., Director	February 25, 2011

WISCONSIN ELECTRIC POWER COMPANY
(Commission File No. 001-01245)

EXHIBIT INDEX
to
Annual Report on Form 10-K
For the year ended December 31, 2010

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to Wisconsin Electric Power Company. (An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32.)

Number	Exhibit
3	Articles of Incorporation and By-laws
3.1*	Restated Articles of Incorporation of Wisconsin Electric Power Company, as amended and restated effective January 10, 1995. (Exhibit (3)-1 to Wisconsin Electric Power Company's 12/31/94 Form 10-K.)
3.2*	Bylaws of Wisconsin Electric Power Company, as amended to May 1, 2000. (Exhibit 3.1 to Wisconsin Electric Power Company's 03/31/00 Form 10-Q.)
4	Instruments defining the rights of security holders, including indentures
4.1*	Reference is made to Article III of the Restated Articles of Incorporation of Wisconsin Electric Power Company. (Exhibit 3.1 herein.)
	<i>Indenture and Securities Resolutions:</i>
4.2*	Indenture for Debt Securities of Wisconsin Electric Power Company (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 to Wisconsin Electric's 12/31/95 Form 10-K.)
4.3*	Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 to Wisconsin Electric's 12/31/95 Form 10-K.)
4.4*	Securities Resolution No. 2 of Wisconsin Electric under the Wisconsin Electric Indenture, dated November 12, 1996. (Exhibit 4.44 to Wisconsin Energy Corporation's 12/31/96 Form 10-K (File No. 001-09057).)
4.5*	Securities Resolution No. 3 of Wisconsin Electric under the Wisconsin Electric Indenture, dated May 27, 1998. (Exhibit (4)-1 to Wisconsin Electric's 06/30/98 Form 10-Q.)
4.6*	Securities Resolution No. 4 of Wisconsin Electric under the Wisconsin Electric Indenture, dated November 30, 1999. (Exhibit 4.46 to Wisconsin Electric's 12/31/99 Form 10-K.)
4.7*	Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.)

EXHIBIT INDEX - (Cont'd)

Number	Exhibit
4.8*	Securities Resolution No. 6 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 17, 2004. (Exhibit 4.48 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-113414), filed November 23, 2004.)
4.9*	Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 to Wisconsin Electric's Form 8-K, dated November 2, 2006.)
4.10*	Securities Resolution No. 8 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of September 25, 2008. (Exhibit 4.1 to Wisconsin Electric's 09/25/08 Form 8-K.)
4.11*	Securities Resolution No. 9 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2008. (Exhibit 4.1 to Wisconsin Electric's 12/08/08 Form 8-K.)
4.12*	Securities Resolution No. 10 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2009. (Exhibit 4.1 to Wisconsin Electric's 12/08/09 Form 8-K.)
	Certain agreements and instruments with respect to unregistered long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiary on a consolidated basis have been omitted as permitted by related instructions. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and instruments.
10	Material Contracts
10.1*	Asset Sale Agreement by and among Wisconsin Electric Power Company, FPL Energy Point Beach, LLC, as Buyer, and FPL Group Capital Inc., as Buyer's Parent, dated December 19, 2006 (the "Asset Sale Agreement"). (Exhibit 2.1 to Wisconsin Energy Corporation's 12/31/06 Form 10-K (File No. 001-09057).)
10.2*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC, dated May 24, 2007, which effectively amends the Asset Sale Agreement. (Exhibit 2.1 to Wisconsin Energy Corporation's 06/30/07 Form 10-Q (File No. 001-09057).)
10.3*	Letter Agreement between Wisconsin Electric Power Company, FPL Energy Point Beach, LLC and FPL Group Capital, Inc., dated September 28, 2007, which amends the Asset Sale Agreement. (Exhibit 2.3 to Wisconsin Energy Corporation's 09/28/07 Form 8-K (File No. 001-09057).)
10.4*	Wisconsin Energy Corporation Supplemental Pension Plan, effective as of January 1, 2005. (Exhibit 10.9 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.5*	Service Agreement, dated April 25, 2000, between Wisconsin Electric Power Company and Wisconsin Gas Company (n/k/a Wisconsin Gas LLC). (Exhibit 10.32 to Wisconsin Energy Corporation's 12/31/00 Form 10-K (File No. 001-09057).)

EXHIBIT INDEX - (Cont'd)

Number	Exhibit
10.6*	Service Agreement, dated December 29, 2000, between Wisconsin Electric Power Company and American Transmission Company LLC. (Exhibit 10.33 to Wisconsin Energy Corporation's 12/31/00 Form 10-K (File No. 001-09057).)
10.7*	Executive Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of July 23, 2004 (including amendments approved effective as of November 2, 2005) (the "Legacy EDCP") (Exhibit 10.2 to Wisconsin Energy Corporation's 09/30/05 Form 10-Q (File No. 001-09057).)** See Note.
10.8*	First Amendment to the Legacy EDCP, effective as of January 1, 2005. (Exhibit 10.12 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.9*	Wisconsin Energy Corporation Executive Deferred Compensation Plan, effective as of January 1, 2005. (Exhibit 10.13 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.10*	Directors' Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of May 1, 2004 (the "Legacy DDCP"). (Exhibit 10.3 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q (File No. 001-09057).)** See Note.
10.11*	First Amendment to the Legacy DDCP, effective as of January 1, 2005. (Exhibit 10.15 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.12*	Wisconsin Energy Corporation Directors' Deferred Compensation Plan, effective as of January 1, 2005. (Exhibit 10.16 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No.001-09057).)** See Note.
10.13*	Wisconsin Energy Corporation Death Benefit Only Plan, as amended and restated as of July 22, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/10 Form 10-Q (File No. 001-09057).)** See Note.
10.14*	Wisconsin Energy Corporation Short-Term Performance Plan, as amended and restated effective as of January 1, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/03/09 Form 8-K (File No. 001-09057).)** See Note.
10.15*	Wisconsin Energy Corporation Amended and Restated Executive Severance Policy, effective as of January 1, 2008. (Exhibit 10.18 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.16*	Restated Non-Qualified Trust Agreement by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 11, 2004, regarding trust established to provide a source of funds to assist in meeting of the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy corporation or its subsidiaries and various plan participants. (Exhibit 10.16 to Wisconsin Energy Corporation's 12/31/07 Form 10-K (File No. 001-09057).)** See Note.
10.17*	Base Salaries of Named Executive Officers of the Registrant. (Exhibit 10.19 to Wisconsin Energy Corporation's 12/31/10 Form 10-K (File No. 001-09057).)** See Note.

EXHIBIT INDEX - (Cont'd)

Number	Exhibit
10.18*	Affiliated Interest Agreement (Service Agreement), dated December 12, 2002, by and among Wisconsin Energy Corporation and its affiliates. (Exhibit 10.14 to Wisconsin Energy Corporation's 12/31/02 Form 10-K (File No. 001-09057).)
10.19*	Employment arrangement with Charles R. Cole, effective August 1, 1999. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/31/00 Form 10-K (File No. 001-09057).)** See Note.
10.20*	Amendment of the employment arrangement with Charles R. Cole, dated December 11, 2008. (Exhibit 10.23 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.21*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Gale E. Klappa, dated as of December 29, 2008. (Exhibit 10.25 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.22*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett, dated as of December 30, 2008. (Exhibit 10.26 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.23*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Frederick D. Kuester, dated as of December 30, 2008. (Exhibit 10.27 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.24*	Letter Agreement by and between Wisconsin Energy Corporation and James C. Fleming, dated as of November 23, 2005, which became effective January 3, 2006. (Exhibit 10.31 to Wisconsin Energy Corporation's 12/31/05 Form 10-K (File No. 001-09057).)** See Note.
10.25*	Amendment to the Letter Agreement between Wisconsin Energy Corporation and James C. Fleming, dated December 23, 2008. (Exhibit 10.29 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.26*	Amended and Restated Senior Officer, Change in Control, Severance and Non-Compete Agreement between Wisconsin Energy Corporation and Kristine A. Rappé, dated as of December 30, 2008. (Exhibit 10.30 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.27*	Supplemental Pension Benefit agreement between Wisconsin Energy Corporation and Stephen Dickson, effective May 23, 2001. (Exhibit 10.1 to Wisconsin Energy Corporation's 06/30/01 Form 10-Q (File No. 001-09057).)** See Note.
10.28*	Amendment to the Supplemental Pension Benefit Agreement between Wisconsin Energy Corporation and Stephen P. Dickson, dated December 29, 2008. (Exhibit 10.32 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.

Number	Exhibit
10.29*	Amended and Restated Non-Compete and Special Severance Tax Protection Agreement between Wisconsin Energy Corporation and Stephen P. Dickson, effective as of January 1, 2008. (Exhibit 10.33 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.30*	Forms of Stock Option Agreements under 1993 Omnibus Stock Incentive Plan. (Exhibit 10.5 to Wisconsin Energy Corporation's 12/31/95 Form 10-K.) Updated as Exhibit 10.1(a) and 10.1(b) to Wisconsin Energy Corporation's 03/31/00 Form 10-Q (File No. 001-09057).)** See Note.
10.31*	1998 Revised forms of award agreements under 1993 Omnibus Stock Incentive Plan for non-qualified stock option awards to non-employee directors, restricted stock awards and option awards. (Exhibit 10.11 to Wisconsin Energy Corporation's 12/31/98 Form 10-K (File No. 001-09057).)** See Note.
10.32*	2001 Revised forms of award agreements under 1993 Omnibus Stock Incentive Plan for restricted stock awards, incentive stock option awards and non-qualified stock option awards. (Exhibit 10.3 to Wisconsin Energy Corporation's 03/31/01 Form 10-Q (File No. 001-09057).)** See Note.
10.33*	1993 Omnibus Stock Incentive Plan, as approved by Wisconsin Energy Corporation's stockholders at its 2001 annual meeting of stockholders, amended and restated effective as of January 1, 2008. (Exhibit 10.37 to Wisconsin Energy Corporation's 12/31/08 Form 10-K (File No. 001-09057).)** See Note.
10.34*	2005 Terms and Conditions Governing Non-Qualified Stock Option Award under 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/28/04 Form 8-K (File No. 001-09057).)** See Note.
10.35*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q (File No. 001-09057).)** See Note.
10.36*	Terms and Conditions Governing Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan, approved December 3, 2009. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/03/09 Form 8-K (File No. 001-09057).)** See Note.
10.37*	Terms and Conditions Governing Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan, approved December 1, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/01/10 Form 8-K (File No. 001-09057).)** See Note.
10.38*	Wisconsin Energy Corporation Performance Unit Plan, amended and restated effective as of January 1, 2010. (Exhibit 10.2 to Wisconsin Energy Corporation's 12/03/09 Form 8-K (File No. 001-09057).)** See Note.
10.39*	Form of Award of Performance Units under the Wisconsin Energy Corporation Performance Unit Plan. (Exhibit 10.2 to Wisconsin Energy Corporation's 12/06/04 Form 8-K (File No. 001-09057).)** See Note.

EXHIBIT INDEX - (Cont'd)

Number	Exhibit
10.40*	Port Washington I Facility Lease Agreement between Port Washington Generating Station LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q.)
10.41*	Port Washington II Facility Lease Agreement between Port Washington Generating Station LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q.)
10.42*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K (File No. 001-09057).)
10.43*	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K (File No. 001-09057).)
10.44*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q (File No. 001-09057).)
10.45*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC, dated October 31, 2007, which amends the PPA. (Exhibit 10.45 to Wisconsin Energy Corporation's 12/31/07 Form 10-K (File No. 001-09057).)
	Note: Two asterisks (**) identify management contracts and executive compensation plans or arrangements required to be filed as exhibits pursuant to Item 15(b) of Form 10-K.
12	Statements re Computation of Ratios
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges.
21	Subsidiaries of the registrant
21.1	Subsidiaries of Wisconsin Electric Power Company.
31	Rule 13a-14(a)/15d-14(a) Certifications
31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

EXHIBIT INDEX - (Cont'd)

Number	Exhibit
32	Section 1350 Certifications
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.