
**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, 2009**

<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, 2009 (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, 2010):

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 29, 2010, are incorporated by reference into Part III hereof.

WISCONSIN ELECTRIC POWER COMPANY
FORM 10-K REPORT FOR THE YEAR ENDED DECEMBER 31, 2009

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Wisconsin Electric Subsidiary and Affiliates

Primary Subsidiary and Affiliates

Bostco	Bostco LLC
Edison Sault	Edison Sault Electric Company
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
ERS	Elm Road Services, LLC

Federal and State Regulatory Agencies

DOA	Wisconsin Department of Administration
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
NRC	United States Nuclear Regulatory 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
CAVR	Clean Air Visibility Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CO ₂	Carbon Dioxide
CWA	Clean Water Act
MACT	Maximum Achievable Control Technology
NOV	Notice of Violation
NO _x	Nitrogen Oxide
PM _{2.5}	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

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:

Other Terms and Abbreviations

ALJ	Wisconsin Administrative Law Judge
ANPR	Advanced Notice of Proposed Rulemaking
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
Fitch	Fitch Ratings
FPL	FPL Group, Inc.
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
MAIN	Mid-America Interconnected Network, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Moody's	Moody's Investor Service
NMC	Nuclear Management Company, LLC
NYMEX	New York Mercantile Exchange
OTC	Over-the-Counter
PJM	PJM Interconnection, L.L.C.
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PRSG	Planning Reserve Sharing Groups
PTF	<i>Power the Future</i>
PUHCA 2005	Public Utility Holding Company Act of 2005
RFC	Reliability First Corporation
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organizations
Settlement Agreement	Settlement Agreement and Release between ERS and Bechtel effective as of December 16, 2009
S&P	Standard & Poor's Ratings Services
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.

Measurements

Btu	British thermal unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

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
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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, 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 unusual weather conditions; 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 economic climate in our service territories such as customer growth; customer business conditions, including demand for their products and services; and changes in market demand and demographic patterns.
- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery for new investments as part of Wisconsin Energy's PTF strategy, environmental compliance, transmission service, fuel costs and costs associated with the MISO Energy Markets.
- Regulatory factors such as changes in rate-setting policies or procedures; changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; 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.
- Increased competition in our electric and gas markets and continued industry consolidation.
- Factors which impede or delay execution of Wisconsin Energy's PTF strategy, including the adverse interpretation or enforcement of permit conditions by the permitting agencies; construction delays; and obtaining the investment capital from outside sources necessary to implement the strategy.
- The impact of recent and future federal, state and local legislative and regulatory changes, including electric and gas industry restructuring initiatives; changes to the Federal Power Act and related regulations under the Energy Policy Act and enforcement thereof by 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; and changes in the application of existing laws and regulations.
- The cost and other effects of legal and administrative proceedings, settlements, investigations, claims and changes in those matters.

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

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

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 1,117,400 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 462,400 gas customers in Wisconsin and approximately 465 steam customers in metropolitan Milwaukee, Wisconsin. For further financial information about our business segments, see Results of Operations in Item 7 and Note P -- Segment Reporting in the Notes to Consolidated Financial Statements in Item 8.

Wisconsin Energy is also the parent company of Wisconsin Gas, a natural gas distribution utility, which serves customers throughout Wisconsin; Edison Sault, an electric utility which serves customers in the Upper Peninsula of Michigan; 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".

PTF Strategy: In September 2000, Wisconsin Energy announced its PTF strategy to improve the supply and reliability of electricity in Wisconsin. As part of the PTF strategy, Wisconsin Energy is: (1) investing in new natural gas-fired and coal-fired electric generating facilities, (2) upgrading our existing electric generating facilities and (3) investing in upgrades of our existing energy distribution system. Additional information concerning PTF may be found below under Utility Operations as well as in Item 7.

Other: Bostco is our non-utility subsidiary that develops and invests in real estate. As of December 31, 2009, Bostco had \$35.9 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 in 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

We are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits, 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.

ITEM 1. BUSINESS - (Cont'd)

Our electric energy sales to all classes of customers totaled approximately 28.9 million MWh during 2009 and approximately 31.7 million MWh during 2008. We had approximately 1,117,400 electric customers as of December 31, 2009 and 1,114,800 electric customers as of December 31, 2008.

Electric Sales Growth: Our service territory experienced a significant economic recession during late 2008 and into 2009. Our normalized 2009 electric sales, excluding our two largest customers, two iron ore mines, were approximately 5.6% lower than our normalized 2008 electric sales. As we look toward 2010 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. We also anticipate that our peak electric demand will grow at an annual rate of 1.0% to 1.5% over the next five years.

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 5.3% and 6.6% of our total electric utility energy sales during 2009 and 2008, respectively. Effective January 1, 2008, the mines became eligible to receive electric service from us in accordance with tariffs approved by the MPSC. Prior to this, we had special negotiated power-sales contracts with these mines.

Sales to Wholesale Customers: During 2009, we sold wholesale electric energy to two municipally owned systems, two rural cooperatives and two municipal joint action agencies located in the states of Wisconsin and Michigan. We also made wholesale electric energy sales to twelve other public utilities and power marketers throughout the region under rates approved by FERC. Wholesale sales accounted for approximately 10.7% of our total electric energy sales and 6.1% of total electric operating revenues during 2009, compared with 11.1% of total electric energy sales and 4.3% of total electric operating revenues during 2008.

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. We are a member of the RFC, a reliability council which has approved reliability standards setting forth the methodology for establishing planning reserve requirements and requiring the formation of PRSG. We are also a member of the Midwest PRSG, which was formed to establish planning reserve requirements. As a member of the Midwest PRSG, we were required to adhere to PSCW guidelines requiring an 18% planning reserve margin. In October 2008, the PSCW issued an order lowering the planning reserve margin requirement from 18% to 14.5% effective for planning year two and each year beyond, and the MISO calculated the planning reserve margin for the first planning year 2009-2010. The MPSC has not yet established guidelines in this area.

We had adequate capacity to meet all of our firm electric load obligations during 2009 and expect to have adequate capacity to meet all of our firm obligations during 2010. 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 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)		
	2009	2008	2007
Coal (b) (c)	3,131	3,247	3,247
Natural Gas - Combined Cycle (d)	1,090	1,090	545
Natural Gas/Oil - Peaking Units (e)	1,150	1,138	1,157
Renewables (f)	86	86	57
Total	<u>5,457</u>	<u>5,561</u>	<u>5,006</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) OC 1 was placed in service on February 2, 2010, and our share of this unit's dependable capability is 515 MW. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010, and our share of this unit's dependable capability will also be 515 MW.
- (c) In October 2009, Presque Isle Units 3 and 4 were retired. These units represented 116 MW of dependable capability.
- (d) The increase in 2008 as compared to 2007 reflects the May 2008 in-service of PWGS 2, which has a dependable capability of 545 MW.
- (e) 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.
- (f) 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, 2009, as well as an estimate for 2010:

	Estimate	Actual		
	2010	2009	2008	2007
Coal (a)	59.1%	52.8%	57.3%	54.8%
Nuclear (b)	N/A	N/A	N/A	17.5%
Wind	1.5%	1.2%	0.6%	- %
Hydroelectric	0.8%	0.8%	0.9%	1.0%
Natural Gas - Combined Cycle	8.1%	7.6%	5.3%	5.3%
Natural Gas/Oil - Peaking Units	0.2%	0.2%	0.3%	0.8%
Net Generation	69.7%	62.6%	64.4%	79.4%
Purchased Power (b)	30.3%	37.4%	35.6%	20.6%
Total	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>

- (a) OC 1 was placed in service on February 2, 2010, and we are entitled to 515 MW of this unit's dependable capability. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010, and we are entitled to 515 MW of this unit's dependable capability.
- (b) Beginning in 2007, nuclear generation decreased due to the sale of Point Beach and purchased power increased as a result of the entry into the associated power purchase agreement with the buyer.

ITEM 1. BUSINESS - (Cont'd)

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
Coal	\$ 25.01	\$ 22.93	\$ 20.52
Nuclear	N/A	N/A	\$ 5.83
Natural Gas - Combined Cycle	\$ 51.67	\$ 69.65	\$ 61.27
Natural Gas/Oil - Peaking Units	\$121.18	\$160.25	\$111.21
Purchased Power	\$ 42.21	\$ 46.67	\$ 46.11

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 typically 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.

Natural gas costs have been volatile. We have a PSCW-approved hedging program to help manage our natural gas price risk. 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 2009, 2008 and 2007 average costs of natural gas and purchased power shown above.

Coal-Fired Generation

Our coal-fired generation consists of 17 generating units as of December 31, 2009. In addition, OC 1 was placed into service in February 2010. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010.

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 2010, 100% of our projected coal requirements of 11.6 million tons are under contracts which are not tied to 2010 market pricing fluctuations. In 2009, our coal-fired generation consisted of six operating plants with a dependable capability of approximately 3,131 MW. However, by the end of 2010, with the addition of OC 1 and the scheduled addition of OC 2, we expect our coal-fired generation to have a dependable capability of 4,161 MW.

Following is a summary of the annual tonnage amounts for our principal long-term coal contracts by the month and year in which the contracts expire:

<u>Contract Expiration Date</u>	<u>Annual Tonnage (Thousands)</u>
Dec. 2010	11,765
Dec. 2011	9,480
Dec. 2012	5,000

Coal Deliveries: Approximately 88% of our 2010 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.

ITEM 1. BUSINESS - (Cont'd)

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. The PSCW has approved a program that allows 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. The costs of this program are included in our fuel and purchased power costs.

During the fourth quarter of 2009, we reached a contingent agreement to sell our 25% interest in Edgewater Generating Unit 5 to WPL, which will become binding if we are unable to reach an agreement with a third party to sell our interest. We are continuing to negotiate with a third party to sell our interest in this unit. The completion of any sale will be subject to approval by the PSCW.

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 five operating plants with a dependable capability of approximately 1,983 MW as of December 31, 2009. We added PWGS 1 and 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 the plants. We have firm and interruptible transportation, balancing and storage agreements intended to support the plants' variable usage.

The PSCW has approved a program that allows us to hedge up to 75% of our estimated gas usage for electric generation in order to help manage our natural gas price risk. 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, 2009. 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, 2009. 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. We entered into a conditional turbine agreement for the new wind facility and filed a revised, lower cost estimate with the PSCW in May 2009 of \$335.2 million to \$413.5 million, excluding AFUDC. In January 2010, the PSCW approved the CPCN. We currently expect to install up to 90 wind turbines with generating capacity of up to approximately 207 MW, subject to turbine selection and the final site configuration. We expect 2012 to be the first full year of operation.

ITEM 1. BUSINESS - (Cont'd)

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 sawdust 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 either the federal production tax credit or the federal 30% investment tax credit. We currently expect the plant to cost approximately \$250 million and to be completed during the fall of 2013, subject to regulatory approvals. We expect to file a request for a Certificate of Authority for the project in the first quarter of 2010.

Nuclear Generation

Point Beach: Prior to September 28, 2007, we owned two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. On September 28, 2007, we sold Point Beach to an affiliate of FPL for approximately \$924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel and associated inventories, and assumed the obligation to decommission the plant.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, we are purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we will be paying the buyer a predetermined price per MWh for energy delivered. For additional information on the sale of Point Beach, see Note H -- Nuclear Operations in the Notes to Consolidated Financial Statements in Item 8 and Nuclear Operations under Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Used Nuclear Fuel Storage & Disposal: For information concerning used nuclear fuel storage and disposal issues, see Nuclear Operations under Factors Affecting Results, Liquidity and Capital Resources in Item 7.

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, 2009 with unaffiliated parties for the next five years:

<u>Year</u>	<u>MW Under Power Purchase Commitments (a)</u>
2010	1,599
2011	1,599
2012	1,440
2013	1,269
2014	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.

In addition, as part of Wisconsin Energy's PTF strategy, we are leasing three of the four new operating units from We Power under long-term leases that have been approved by the PSCW. We are responsible for all of the operating costs, including fuel, of the PTF units once they are placed in service, and we will recover the operating costs of these plants in rates. PWGS 1 and PWGS 2, each with a dependable capability of 545 MW, were placed in service in July 2005 and May 2008, respectively. OC 1 was placed into service on February 2, 2010. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010. We are entitled to 515 MW from each unit.

ITEM 1. BUSINESS - (Cont'd)**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, 2009 and 2008.

MISO: 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 a new 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.

Electric Hedging Programs: We purchase some of the electricity needed to satisfy our current sales obligations in the MISO Energy Markets. Due to volatility in the price of market-based energy, we face potential financial exposure. We have PSCW approval to hedge up to 75% of a future month's predicted electricity need. This plan seeks to manage market price risk, as well as reduce price risks related to forced outages.

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

The following table shows certain electric utility operating statistics from 2005 to 2009 for electric operating revenues, MWh sales and customer data:

SELECTED CONSOLIDATED ELECTRIC UTILITY OPERATING DATA					
Year Ended December 31	2009	2008	2007	2006	2005
Operating Revenues (Millions)					
Residential	\$977.6	\$962.5	\$915.5	\$870.8	\$815.6
Small Commercial/Industrial	860.3	869.7	840.6	796.0	727.6
Large Commercial/Industrial	599.4	646.3	664.2	637.0	592.7
Other - Retail	21.2	20.8	19.2	18.9	17.5
Total Retail Sales	2,458.5	2,499.3	2,439.5	2,322.7	2,153.4
Wholesale - Other	116.7	77.7	83.5	68.1	85.6
Resale - Utilities	47.5	37.7	110.7	73.5	42.5
Other Operating Revenues	62.3	45.9	40.9	35.2	39.4
Total Operating Revenues	\$2,685.0	\$2,660.6	\$2,674.6	\$2,499.5	\$2,320.9
MWh Sales (Thousands)					
Residential	7,949.3	8,277.1	8,416.1	8,154.0	8,389.6
Small Commercial/Industrial	8,571.6	9,023.7	9,185.4	8,899.0	8,943.9
Large Commercial/Industrial	9,140.3	10,691.7	11,036.7	10,972.2	11,489.8
Other - Retail	156.5	161.5	162.4	163.7	166.5
Total Retail Sales	25,817.7	28,154.0	28,800.6	28,188.9	28,989.8
Wholesale - Other	1,529.4	2,620.7	1,939.6	1,819.0	2,300.6
Resale - Utilities	1,548.9	881.0	1,920.7	1,436.2	682.8
Total Sales	28,896.0	31,655.7	32,660.9	31,444.1	31,973.2
Customers - End of Year (Thousands)					
Residential	1,001.2	999.1	995.6	990.4	982.4
Small Commercial/Industrial	113.1	112.6	110.8	108.7	106.9
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	1,117.4	1,114.8	1,109.5	1,102.2	1,092.4
Customers - Average (Thousands)	1,115.5	1,111.8	1,105.5	1,097.6	1,086.9
Degree Days (a)					
Heating (6,640 Normal)	6,825	7,073	6,508	6,043	6,628
Cooling (698 Normal)	475	593	800	723	949

(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 862.5 million therms during 2009, a 4.3% decrease compared with 2008. As of December 31, 2009, we were transporting gas for approximately 400 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 34.6% of the total volumes delivered during 2009, 34.8% during 2008 and 37.8% during 2007. We had approximately 462,400 and 460,500 gas customers as of December 31, 2009 and 2008, respectively. Our peak daily send-out during 2009 was 714,803 Dth on January 15, 2009.

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, 2014 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 portfolios. We have extended our commitment on Guardian's original pipeline through December 2022. We have committed to purchase additional capacity through October 2023 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.

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 GCRM. During 2009, we continued our active participation 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 NYMEX based natural gas options, (ii) up to 15% of planned flowing gas supply using NYMEX based natural gas future contracts and (iii) up to 35% of planned storage withdrawals using NYMEX based natural gas options. 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 from 2005 to 2009 for gas operating revenues, therms delivered and customer data:

SELECTED CONSOLIDATED GAS UTILITY OPERATING DATA					
Year Ended December 31	2009	2008	2007	2006	2005
Operating Revenues (Millions)					
Residential	\$365.9	\$445.8	\$390.0	\$363.5	\$378.4
Commercial/Industrial	189.7	238.5	202.8	191.7	205.0
Interruptible	3.5	6.0	5.2	4.6	4.9
Total Retail Gas Sales	559.1	690.3	598.0	559.8	588.3
Transported Gas	12.9	14.3	15.1	14.9	15.0
Other Operating Revenues	(7.8)	4.6	(1.2)	15.3	(9.7)
Total Operating Revenues	\$564.2	\$709.2	\$611.9	\$590.0	\$593.6
Therms Delivered (Millions)					
Residential	349.4	364.7	342.6	313.2	340.5
Commercial/Industrial	208.8	216.2	199.6	190.3	199.9
Interruptible	5.9	6.9	7.1	6.0	6.2
Total Retail Gas Sales	564.1	587.8	549.3	509.5	546.6
Transported Gas	298.4	313.3	333.7	303.1	355.8
Total Therms Delivered	862.5	901.1	883.0	812.6	902.4
Customers - End of Year (Thousands)					
Residential	423.8	422.0	419.1	415.1	409.5
Commercial/Industrial	38.2	38.1	37.7	37.1	36.5
Transported Gas	0.4	0.4	0.4	0.4	0.4
Total Customers	462.4	460.5	457.2	452.6	446.4
Customers - Average (Thousands)	460.8	458.3	454.5	449.1	441.6
Degree Days (a)					
Heating (6,640 Normal)	6,825	7,073	6,508	6,043	6,628

(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 2009, the steam utility had \$39.1 million of operating revenues from the sale of 2,932 million pounds of steam compared with \$40.3 million of operating revenues from the sale of 3,081 million pounds of steam during 2008. As of December 31, 2009 and 2008, steam was used by approximately 465 customers 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

As required by PUHCA 2005, enacted under the Energy Policy Act, we notified FERC of our status as a holding company by reason of our ownership interest in ATC and sought from FERC exemption from the requirements of PUHCA 2005. In June 2006, we received notice from FERC confirming our status as a holding company and granting such exemption.

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 co-generation 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, replacing the voluntary standards developed by the North American Electric Reliability Corporation, and which has the authority to levy monetary sanctions for failure to comply with the new 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 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 regulation of FERC with respect to wholesale power service, electric reliability requirements and accounting. 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, 2009:

	2009		2008		2007	
	Amount	Percent	Amount	Percent	Amount	Percent
	(Millions of Dollars)					
Wisconsin						
Electric Utility - Retail	\$2,379.2	72.3%	\$2,416.8	70.8%	\$2,331.1	70.2%
Gas Utility - Retail	564.2	17.2%	709.2	20.8%	611.9	18.4%
Steam Utility - Retail	39.1	1.2%	40.3	1.2%	35.1	1.1%
Total	<u>2,982.5</u>	<u>90.7%</u>	<u>3,166.3</u>	<u>92.8%</u>	<u>2,978.1</u>	<u>89.7%</u>
Michigan						
Electric Utility - Retail	141.6	4.3%	128.4	3.8%	149.3	4.5%
FERC						
Electric Utility - Wholesale	164.2	5.0%	115.4	3.4%	194.2	5.8%
Total Utility Operating Revenues	<u>\$3,288.3</u>	<u>100.0%</u>	<u>\$3,410.1</u>	<u>100.0%</u>	<u>\$3,321.6</u>	<u>100.0%</u>

Our operations are also subject to regulations, where applicable, of the EPA, the WDNR, the MDEQ and the Michigan Department of Natural Resources.

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

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%. 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. Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the DOA back to the PSCW and/or contracted third parties. In addition, Act 141 requires that 1.2% of utilities' annual operating revenues be used to fund these programs. In July 2008, the Governor of Wisconsin's Task Force on Global Warming, which was established in 2007, issued a final report that recommended that the energy efficiency goal be based on achieving efficiency resulting in a 2% reduction in electric load annually starting in 2015 rather than a goal based on a percent of revenue. The Task Force's report also includes an increased renewable portfolio standard. Under the Task Force's recommendations, the renewable portfolio standard would increase to 10% by 2013, 20% by 2020 and 25% by 2025.

In December 2009, legislation covering the Task Force recommendations was introduced in the Wisconsin legislature. We are working within the context of the Task Force to provide comments where we believe the proposed legislation deviates from the Task Force recommendations.

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 ash, 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-ash landfills, manufactured gas plant sites and air quality, see Note R -- 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 \$188 million in 2009 compared with \$135 million in 2008. Expenditures incurred during 2008 and 2009 primarily included costs associated with the installation of pollution abatement facilities at our power plants. These expenditures are expected to approximate \$300 million during 2010, reflecting NO_x, 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 \$66.7 million and \$67.2 million during 2009 and 2008, respectively.

ITEM 1. BUSINESS - (Cont'd)**Coal-Ash Landfills**

We currently have a successful program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and synthetic gypsum, which avoids the need for disposal in specially-designed landfills. Some early designed and constructed coal-ash landfills, which we used prior to 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 at 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, 2009, we had 4,123 total employees, of which 2,720 were represented under labor agreements with the following bargaining units:

	<u>Number of Employees</u>	<u>Expiration Date of Current Labor Agreement</u>
Local 2150 of International Brotherhood of Electrical Workers	1,925	August 15, 2010
Local 317 of International Union of Operating Engineers	491	March 31, 2011
Local 2006 Unit 5 of United Steel Workers	168	November 1, 2011
Local 510 of International Brotherhood of Electrical Workers	136	April 30, 2010
Total	<u>2,720</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. Further, our hydroelectric facilities are regulated by FERC, and FERC also regulates our wholesale power service practices and electric reliability requirements. 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 89% of our electric revenues are regulated by the PSCW, 5% 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 or We Power's control could adversely affect project costs and completion of OC 2 and other construction projects.

Under Wisconsin Energy's PTF strategy, we expect to meet a significant portion of our future generation needs through the leasing of two 545 MW natural gas-fired generating units at PWGS and two 615 MW coal-fired generating units (of which we will be entitled to 515 MW each) located adjacent to our existing Oak Creek Power Plant. PWGS 1 and PWGS 2, which have a dependable capability of 545 MW each, were placed in service in July 2005 and May 2008, respectively. OC 1 was placed into service on February 2, 2010. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010.

Large construction projects of this type, as well as the construction of renewable energy generation and environmental improvements, are subject to usual construction risks over which we and We Power 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 general contractor or subcontractors 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 laws 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.

We face significant costs of compliance with existing and future environmental regulations.

Our operations are subject to extensive environmental regulations by state and federal environmental agencies governing, among other things, air emissions such as 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.

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

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. 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.

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.

In addition, 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.

We could face significant costs if coal ash is regulated as a hazardous waste.

We currently have a successful program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and synthetic gypsum, which avoids the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. Recently, however, the EPA stated that it is considering classifying coal ash as a hazardous waste. If coal ash is classified as a 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 ash.

In addition, if coal ash is classified as hazardous waste and we terminate our coal ash utilization program, we could be required to dispose of the coal ash at a significant cost to the Company.

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. Legislation continues to be considered in the United States Congress that would compel greenhouse gas emission reductions. The American Clean Energy and Security Act of 2009 passed the U.S. House of Representatives in June 2009. The bill, among other things, (i) establishes a federal renewable energy standard; (ii) permits energy efficiency measures to satisfy part of the renewable energy standard; and (iii) establishes a cap-and-trade program to reduce greenhouse gas emissions from various sectors of the economy, including electric and natural gas utilities. Similar legislation is currently being considered in the U.S. Senate and could result in the passage of enforceable federal standards, such as a cap-and-trade program, governing greenhouse gas emissions.

Legislation to regulate greenhouse gases and establish renewable and efficiency standards is also being 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 is currently considering similar legislation addressing renewable energy and efficiency standards. In

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

addition, the Governors of both Michigan and Wisconsin have signed on to the "Midwestern Greenhouse Gas Reduction Accord" and the associated "platform" document developed through the Midwestern Governors Association. These state and regional initiatives could lead to legislation and regulation of greenhouse gas emissions that could be implemented sooner and/or independent of federal regulation, and could be more stringent than any federal legislation that is adopted.

In addition to these federal and state legislative efforts, the EPA is pursuing regulation of greenhouse gases using its existing authority under the CAA. On December 7, 2009, the EPA issued its long-expected endangerment finding. This determination provides that the atmospheric mix of six greenhouse gases endanger public health and welfare. The determination specifically addresses only the contribution to air pollution of greenhouse gas emissions from motor vehicles and itself has no immediate regulatory effect. However, in combination with a separate EPA rulemaking that will establish limits on greenhouse gas emissions from new motor vehicles, the endangerment finding sets in motion a regulatory process that would likely lead to widespread regulation of greenhouse gas emissions from stationary sources, including electric generating units, absent legislative or other intervention by the Administration. Regulation of greenhouse gas emissions from power plants will impact our ability to do maintenance or modify our existing facilities, and permit new facilities.

In September 2009, the EPA issued two proposals intended to provide guidance on, and effectively change, how the CAA's existing permitting requirements could be applied to sources of greenhouse gas emissions in all sectors of the economy, including major stationary sources of air pollutants such as electric generating plants. The endangerment finding, the regulation of greenhouse gas emissions from motor vehicles and these two additional proposals would provide a framework for the EPA to regulate greenhouse gas emissions from major sources under the CAA.

Some states and environmental groups are also bringing lawsuits against electric utilities and others to force reductions in greenhouse gas emissions. A decision in the U.S. Court of Appeals for the Second Circuit has made it easier for lawsuits to move forward based upon the alleged public nuisance of climate change. The Second Circuit ruled that the plaintiffs in that case have standing to file suit against six 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. The U.S. Court of Appeals for the Fifth Circuit reached a similar conclusion in another nuisance lawsuit involving climate change. Based on these recent decisions, this type of litigation may increase in frequency.

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 program that may be adopted, either at the federal, state or regional level, or other legislation, regulation or order designed to reduce greenhouse gas emissions could make some of our electric generating units uneconomic to maintain and could have a material adverse impact on our electric generation and natural gas distribution operations, cash flows and 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 ratings downgrade, prevailing market conditions, failures of financial institutions or other factors, our results of operations and financial condition could be materially and adversely affected.

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

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, we bear the regulatory risk for the recovery of fuel and purchased power costs when those costs are higher than the forecast of fuel and purchased power costs used to determine the base rate established in our 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.

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.

ITEM 1A. RISK FACTORS - (Cont'd)***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 the economic cycles of the customers we serve. As a result of the significant downturn in the economy during 2008 and 2009, we saw a deterioration in regional economic conditions. As the demand for products produced in our service area declines, we ordinarily experience reduced demand for electricity and/or natural gas. 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 further 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 as a result of the significant downturn in the economy during 2008 and 2009 or otherwise has, to a limited extent, and could continue to have, a material adverse impact on our cash flow, financial condition or results of operations.

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.

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 potentially affects our Michigan operations. Under retail access legislation, customers are permitted to choose their own electric generation supplier. All Michigan electric customers were able to choose their electric generation supplier beginning in January 2002. 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.

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

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 the bid-based energy markets that are part of the MISO Energy Markets on April 1, 2005. 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 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. In addition, in January 2009, MISO implemented an Ancillary Services Market for operating reserves that was simultaneously co-optimized with MISO's existing energy markets.

The new 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.

ITEM 2. PROPERTIES - (Cont'd)

As of December 31, 2009, we owned or leased the following generating stations:

Name	Fuel	No. of Generating Units	Dependable Capability in MW (a)
Coal-Fired Plants			
Oak Creek (b)	Coal	4	1,139
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		17	3,131
Hydro Plants (13 in number)			
Port Washington Generating Station (d)	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 (e)	Wind	2	-
Blue Sky Green Field (f)	Wind	88	29
Total System		157	5,457

- (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 1 was placed into service on February 2, 2010. See Note T -- Subsequent Events for additional information. Bechtel is targeting the commercial operation of OC 2 by the end of August 2010. Our share of the dependable capability of these units is estimated to be 1,030 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. We are continuing to negotiate with a third party to sell our interest in this unit. Any sale will be subject to PSCW approval.
- (d) Effective July 2005 and May 2008, we began leasing PWGS 1 and PWGS 2, respectively, from We Power under 25 year leases. Both units are natural gas-fired generation units with 545 MW each of dependable capability.
- (e) 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.
- (f) 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, 2009, our electric utility operated approximately 22,280 pole-miles of overhead distribution lines and 23,435 miles of underground distribution cable, as well as approximately 337 distribution substations and 284,974 line transformers.

As of December 31, 2009, our gas distribution system included approximately 9,375 miles of distribution mains connected at 25 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 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

ITEM 2. PROPERTIES - (Cont'd)

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, 2009, 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 R -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Edgewater Generating Unit 5: In December 2009, the EPA issued a 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 are working with WPL, who is the primary owner and operator of the plants, and the co-owners of the other plants identified in the NOV, to respond to the NOV. At this time, we cannot predict the outcome of this matter. Also in December 2009, the Sierra Club submitted to WPL a notice of intent to file a citizen suit under the CAA. This notice of intent alleged violations of air permitting and opacity requirements at the Edgewater Generating Station.

See Environmental Compliance in Item 1 and Environmental Matters, Manufactured Gas Plant Sites, Ash Landfill Sites and EPA - Consent Decree in Note R -- 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-ash landfills, manufactured gas plant sites and air quality.

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 DOE's breach of contract with us that required the DOE to begin permanently removing used nuclear fuel from Point Beach by January 31, 1998.

ITEM 3. LEGAL PROCEEDINGS - (Cont'd)

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.

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, including the Settlement Agreement with Bechtel, see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the fourth quarter of 2009.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages at December 31, 2009 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 59.

- 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 63.

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

Stephen P. Dickson. Age 49.

- 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 64.

- 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 59.

- 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.

EXECUTIVE OFFICERS OF THE REGISTRANT - (Cont'd)

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 43.

- 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 53.

- 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>2009</u>	<u>2008</u>
	(Millions of Dollars)	
First	\$44.9	\$54.3
Second	44.9	54.3
Third	44.9	204.1
Fourth	44.9	54.3
Total	<u>\$179.6</u>	<u>\$367.0</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 I -- 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>2009</u>	<u>2008</u>	<u>2007</u>	<u>2006</u>	<u>2005</u>
Year Ended December 31					
Earnings available for common stockholder (Millions)	\$ 287.4	\$ 280.1	\$ 287.7	\$ 275.6	\$ 283.6
Operating revenues (Millions)					
Electric	\$ 2,685.0	\$ 2,660.6	\$ 2,674.6	\$ 2,499.5	\$ 2,320.9
Gas	564.2	709.2	611.9	590.0	593.6
Steam	39.1	40.3	35.1	27.2	23.5
Total operating revenues	<u>\$ 3,288.3</u>	<u>\$ 3,410.1</u>	<u>\$ 3,321.6</u>	<u>\$ 3,116.7</u>	<u>\$ 2,938.0</u>
At December 31 (Millions)					
Total assets	\$ 8,871.2	\$ 8,775.4	\$ 8,312.8	\$ 8,257.8	\$ 7,909.2
Long-term debt and capital lease obligations (including current maturities)	\$ 3,092.8	\$ 2,886.4	\$ 1,990.4	\$ 2,152.1	\$ 2,058.5

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars) (a)			
	March		June	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
<u>Three Months Ended</u>				
Total operating revenues	\$ 988.4	\$ 985.9	\$ 723.7	\$ 782.0
Operating income	\$ 158.1	\$ 141.1	\$ 87.2	\$ 86.8
Earnings available for common stockholder	\$ 98.5	\$ 83.6	\$ 51.2	\$ 51.9
	September		December	
<u>Three Months Ended</u>	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Total operating revenues	\$ 738.3	\$ 750.9	\$ 837.9	\$ 891.3
Operating income	\$ 83.4	\$ 119.4	\$ 140.2	\$ 134.6
Earnings available for common stockholder	\$ 52.4	\$ 73.7	\$ 85.3	\$ 70.9

(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; Edison Sault, an electric utility which serves customers in the Upper Peninsula of Michigan; 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

Wisconsin Energy's key corporate strategy is PTF, which was announced in September 2000. This strategy is designed to address Wisconsin's growing electric supply needs by increasing the electric generating capacity in the state while maintaining a fuel-diverse, reasonably priced electric supply. It is also designed to improve the delivery of energy within our distribution systems to meet increasing customer demands and to support our commitment to improved environmental performance. PWGS 1 and PWGS 2, two 545 MW natural gas electric generating units, were placed in service in July 2005 and May 2008, respectively, and OC 1, a 615 MW coal-fired generating unit, was placed in service on February 2, 2010. Although the new guaranteed in-service date is November 28, 2010, the contractor, Bechtel, is currently targeting commercial operation of OC 2, another 615 MW coal-fired generating unit, by the end of August 2010. We are entitled to 515 MW of each unit.

Utility Operations: We continue to realize operating efficiencies through the integration of our operations with those of Wisconsin Gas. These operating efficiencies are expected to continue to increase customer satisfaction and further reduce operating costs. In connection with Wisconsin Energy's PTF strategy, we are improving our existing energy distribution systems and upgrading existing electric generating assets.

Power the Future Strategy: In February 2001, Wisconsin Energy filed a petition with the PSCW that would allow Wisconsin Energy to begin implementing its 10-year PTF strategy to improve the supply and reliability of electricity in Wisconsin. PTF is intended to meet the demand for electricity and ensure a diverse fuel mix while keeping electricity prices reasonable. Under PTF, Wisconsin Energy is (1) investing approximately \$2.7 billion in 2,120 MW of new natural gas-fired and coal-fired generating capacity at existing sites; (2) upgrading our existing electric generating facilities; and (3) investing in upgrades of our existing energy distribution system.

In November 2001, Wisconsin Energy created We Power to design, construct, own and lease the new generating capacity. We will lease each new generating facility from We Power as well as operate and maintain the new plants under 25- to 30-year lease agreements approved by the PSCW. Based upon the structure of the leases, Wisconsin Energy expects to recover the investments in We Power's new facilities over the initial lease term. At the end of the leases, we will have the right to acquire the plants outright at market value or to renew the leases. We expect that payments under the plant leases will be recoverable in rates under the provisions of the Wisconsin Leased Generation Law.

We expect a significant portion of our future generation needs will be met through We Power's construction of the PWGS units and the Oak Creek expansion.

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

The primary risks that remain under PTF are construction risks associated with the schedule and costs for OC 2; changes in applicable laws or regulations; adverse interpretation or enforcement of permit conditions, laws or regulations by the permitting agencies; the ability to obtain necessary operating permits in a timely manner; obtaining the investment capital from outside sources necessary to implement the strategy; governmental actions; and events in the global economy.

For additional information regarding risks associated with the PTF strategy, see Factors Affecting Results, Liquidity and Capital Resources below.

Sale of Point Beach: In September 2007, we sold Point Beach to an affiliate of FPL for approximately \$924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel and associated inventories, and assumed the obligation to decommission the plant. We retained approximately \$506 million of the sales proceeds, which represents the net book value of the assets sold and certain transaction costs. We deferred the net gain on the sale of approximately \$418 million as a regulatory liability and deposited those proceeds into a restricted cash account. In connection with the sale, we also transferred \$390 million of decommissioning funds to the buyer. We then liquidated the balance of the decommissioning trust assets and retained approximately \$552 million, which was also placed into the restricted cash account. At the direction of our regulators, we are using the cash in the restricted cash account and the interest earned on the balance for the benefit of our customers and to pay certain taxes related to the liquidation of the qualified decommissioning trust. For further information on the 2008 and 2010 rate cases, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in this report.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, we are purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we are paying a predetermined price per MWh for energy delivered.

RESULTS OF OPERATIONS

EARNINGS

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.

2008 vs. 2007: Earnings decreased to \$280.1 million in 2008 compared with \$287.7 million in 2007. Operating income decreased \$8.9 million between the comparative periods. During 2008, we experienced less favorable weather in the summer months, which decreased electric sales. In addition, our fuel and purchased power costs increased primarily as a result of the power purchase agreement entered into upon the sale of Point Beach. Finally, our other operation and maintenance expenses were higher primarily due to increased regulatory amortizations allowed in rates. These items were largely offset by our rate increases and increased margin from gas sales due to colder weather.

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

The following table summarizes our consolidated earnings during 2009, 2008 and 2007:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
Utility Gross Margin			
Electric (See below)	\$1,632.9	\$1,431.5	\$1,693.3
Gas (See below)	174.5	182.8	170.0
Steam	<u>26.7</u>	<u>27.1</u>	<u>24.3</u>
Total Gross Margin	1,834.1	1,641.4	1,887.6
Other Operating Expenses			
Other operation and maintenance	1,231.7	1,295.2	1,041.9
Depreciation, decommissioning and amortization	265.1	256.0	269.7
Property and revenue taxes	99.1	96.4	91.7
Amortization of gain	<u>(230.7)</u>	<u>(488.1)</u>	<u>(6.5)</u>
Operating Income	468.9	481.9	490.8
Equity in Earnings of Transmission Affiliate	51.9	45.4	37.9
Other Income and Deductions, net	25.8	9.9	41.7
Interest Expense, net	<u>100.3</u>	<u>86.6</u>	<u>93.0</u>
Income Before Income Taxes	446.3	450.6	477.4
Income Taxes	157.7	169.3	188.5
Preferred Stock Dividend Requirement	<u>1.2</u>	<u>1.2</u>	<u>1.2</u>
Earnings Available for Common Stockholder	<u><u>\$287.4</u></u>	<u><u>\$280.1</u></u>	<u><u>\$287.7</u></u>

In September 2007, we sold Point Beach and commenced purchasing power from the new owner under a power purchase agreement. As a result of the sale and the power purchase agreement, our 2009 and 2008 earnings reflect higher fuel and purchased power costs as compared to 2007. In addition, as it relates to nuclear operating costs, our 2009 and 2008 operating income reflects lower other operation and maintenance costs and lower depreciation, decommissioning and amortization costs as we no longer own Point Beach.

In January 2008, we received a rate order from the PSCW that authorized a 17.2% increase in electric rates to recover increased costs associated with transmission expenses, Wisconsin Energy's PTF program, environmental expenditures, continued investment in renewable and efficiency programs and recovery of previously deferred regulatory assets. The PSCW allowed us to issue bill credits to our customers from the proceeds of the net gain and excess decommissioning funds associated with the sale of Point Beach to mitigate this increase. The PSCW also determined that \$85.0 million of Point Beach proceeds should be immediately applied during the first quarter of 2008 to offset certain regulatory assets. As a result of these bill credits, we estimate that the January 2008 PSCW rate order resulted in a net 3.2% increase in electric rates paid by our Wisconsin customers in 2008 and resulted in another net increase of 3.2% in 2009. The bill credits that we issue to our customers and the proceeds immediately applied to regulatory assets are reflected on our income statement in the amortization of the gain on the sale of Point Beach. As we issue the bill credits, we transfer the cash from a restricted account to an unrestricted account. The transferred cash is equal to the bill credits, less taxes.

**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 2009 with similar information for 2008 and 2007, including a summary of electric operating revenues and electric sales by customer class:

Electric Utility Operations	Electric Revenues and Gross Margin			Electric MWh Sales		
	2009	2008	2007	2009	2008	2007
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	\$977.6	\$962.5	\$915.5	7,949.3	8,277.1	8,416.1
Small Commercial/Industrial	860.3	869.7	840.6	8,571.6	9,023.7	9,185.4
Large Commercial/Industrial	599.4	646.3	664.2	9,140.3	10,691.7	11,036.7
Other - Retail	21.2	20.8	19.2	156.5	161.5	162.4
Total Retail	2,458.5	2,499.3	2,439.5	25,817.7	28,154.0	28,800.6
Wholesale - Other	116.7	77.7	83.5	1,529.4	2,620.7	1,939.6
Resale - Utilities	47.5	37.7	110.7	1,548.9	881.0	1,920.7
Other Operating	62.3	45.9	40.9	-	-	-
Total	<u>\$2,685.0</u>	<u>\$2,660.6</u>	<u>\$2,674.6</u>	<u>28,896.0</u>	<u>31,655.7</u>	<u>32,660.9</u>
Fuel and Purchased Power						
Fuel	518.3	570.6	570.0			
Purchased Power	533.8	658.5	411.3			
Total Fuel and Purchased Power	<u>1,052.1</u>	<u>1,229.1</u>	<u>981.3</u>			
Total Electric Gross Margin	<u>\$1,632.9</u>	<u>\$1,431.5</u>	<u>\$1,693.3</u>			
Weather -- Degree Days (a)						
Heating (6,640 Normal)				6,825	7,073	6,508
Cooling (698 Normal)				475	593	800

(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

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.

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

We currently estimate that 2010 electric revenues will increase because of the impact of the 2010 PSCW rate increase, the reduction in the Point Beach bill credits and a slight increase in sales to large commercial and industrial customers as current economic conditions have improved slightly in our service territory. We would also expect residential sales to increase if we experience normal summer weather. However, we expect sales to small commercial and industrial customers to decrease slightly from 2009. For further information regarding the January 2010 PSCW rate order, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters - 2010 Rate Case.

2008 vs. 2007: Our electric utility operating revenues decreased by \$14.0 million, or 0.5%, when compared to 2007. The largest factor in this decline was a one-time \$62.5 million FERC-approved refund to our wholesale customers associated with their share of the gain on the sale of Point Beach. Consistent with our past practices, the refund was recorded as a reduction in wholesale revenues. Because the refund came from the restricted cash associated with the sale of Point Beach, a corresponding entry was made to amortize the gain on the sale of Point Beach.

We also estimate that weather reduced our revenues by approximately \$28.3 million for the year ended December 31, 2008 as compared to the same period in 2007. As measured by cooling degree days, 2008 was approximately 25.9% cooler than 2007 and 17.5% cooler than normal. Resale sales declined by approximately \$73.0 million partially due to Edison Sault switching from a resale customer to a wholesale customer as of January 1, 2008, and because of less favorable weather, which reduced demand for our higher cost generation that was not being utilized to serve our retail customers. In addition, we experienced a \$9.0 million decrease in revenue related to the settlement of a billing dispute with our largest customers, two iron ore mines, that occurred in 2007. Partially offsetting these decreases, we estimate that our electric revenues were approximately \$142.9 million higher than the same period in 2007 because of pricing increases we received in the January 2008 PSCW rate case, the interim April 2008 and final July 2008 PSCW fuel orders, and a wholesale rate increase effective in May 2007.

Electric Fuel and Purchased Power Expenses

2009 vs. 2008: Our electric fuel and purchased power costs decreased by \$177.0 million, or 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%.

We expect that electric fuel and purchased power expenses in 2010 will be impacted by the price of natural gas, changes in the cost of coal and related transportation prices, and changes in electric sales.

2008 vs. 2007: Our electric fuel and purchased power costs increased by \$247.8 million, or approximately 25.3%, when compared to 2007. The largest factor related to this increase was the power purchase agreement we entered into in connection with the sale of Point Beach, which increased costs by approximately \$247.0 million in 2008. In addition, in connection with the January 2008 PSCW rate order, we recorded a \$41.2 million one-time amortization of deferred fuel costs in the first quarter of 2008. After adjusting for the Point Beach power purchase agreement and one-time amortization of deferred fuel costs, fuel and purchased power costs decreased by approximately \$40.4 million, or 4.1%. Cost increases resulting from higher natural gas prices, purchased energy and coal and related transportation prices were more than offset by lower costs resulting from reduced MWh sales during 2008 as compared to 2007.

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 2009, 2008 and 2007:

Gas Utility Operations	2009	2008	2007
	(Millions of Dollars)		
Operating Revenues	\$564.2	\$709.2	\$611.9
Cost of Gas Sold	389.7	526.4	441.9
Gross Margin	\$174.5	\$182.8	\$170.0

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 2009, 2008 and 2007:

Gas Utility Operations	Gross Margin			Therm Deliveries		
	2009	2008	2007	2009	2008	2007
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	\$117.3	\$120.5	\$113.1	349.4	364.7	342.6
Commercial/Industrial	40.2	41.9	38.7	208.8	216.2	199.6
Interruptible	0.6	0.7	0.7	5.9	6.9	7.1
Total Retail Gas Sales	158.1	163.1	152.5	564.1	587.8	549.3
Transported Gas	14.3	15.8	15.6	298.4	313.3	333.7
Other	2.1	3.9	1.9	-	-	-
Total	\$174.5	\$182.8	\$170.0	862.5	901.1	883.0

Weather -- Degree Days (a)

Heating (6,640 Normal)	6,825	7,073	6,508
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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.

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.

We expect our 2010 gas margin will be impacted by weather; however, as noted above, 2009 was colder than normal.

2008 vs. 2007: Our gas margin increased by \$12.8 million, or approximately 7.5%, when compared to 2007. We estimate that approximately \$3.9 million of this increase related to pricing increases that we received in the January 2008 PSCW rate order. In addition, during 2008, approximately \$2.6 million of additional revenues were earned under the incentive portion of the GCRM. We estimate that weather had a positive impact on our gas margin of approximately \$5.2 million. Temperatures (as measured by heating degree days) were 8.7% colder in 2008 as compared to 2007 and 5.9% colder than normal.

Other Operation and Maintenance Expense

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,

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

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.

Our operation and maintenance expense is influenced by wage inflation, employee benefit costs, plant outages and the amortization of regulatory assets. We expect our 2010 other operation and maintenance expense to increase because of costs associated with the new Oak Creek units and regulatory amortizations.

2008 vs. 2007: Our other operation and maintenance expense increased by approximately \$253.3 million, or 24.3%, when compared to 2007. The January 2008 PSCW rate order allowed for pricing increases related to transmission costs, PTF lease costs and the amortization of other deferred costs. These items were \$243.1 million higher in 2008 as compared to 2007. In addition to these regulatory amortizations, in connection with the January 2008 PSCW rate order, we recorded a one-time \$43.8 million amortization of deferred bad debt costs in the first quarter of 2008. We also incurred approximately \$64.1 million of increased expenses related to the operation and maintenance of our power plants and electric distribution system. These increased costs were also considered in the rate setting process. These increases were partially offset by a \$119.7 million decrease in nuclear operation and maintenance expense related to Point Beach as we sold the plant in September 2007.

Depreciation, Decommissioning and Amortization Expense

2009 vs. 2008: Depreciation, decommissioning 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 into service in May 2008.

We expect depreciation, decommissioning and amortization expense to decrease by approximately \$40 million in 2010 because of new depreciation rates that were implemented in connection with the January 2010 PSCW rate order. The new depreciation rates generally reflect longer lives for our utility assets.

2008 vs. 2007: Depreciation, decommissioning and amortization expense decreased by approximately \$13.7 million, or 5.1%, when compared to 2007. The 2007 sale of Point Beach reduced depreciation, decommissioning and amortization expense by approximately \$24 million. Partially offsetting this decline was higher depreciation related to new projects including the Blue Sky Green Field wind project.

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 2009, 2008 and 2007, the Amortization of Gain was as follows:

Amortization of Gain	2009	2008	2007
	(Millions of Dollars)		
Bill Credits - Retail	\$230.7	\$340.6	\$6.5
One-Time FERC Refund	-	62.5	-
One-Time Amortization to Offset Regulatory Asset	-	85.0	-
Total Amortization of Gain	\$230.7	\$488.1	\$6.5

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

During 2010, we expect to see a reduction in the Amortization of Gain of approximately \$36.0 million related to the scheduled decrease in bill credits to retail customers compared to 2009. We expect that all remaining bill credits will be issued by the end of 2010.

Other Income and Deductions, net

The following table identifies the components of consolidated other income and deductions, net during 2009, 2008 and 2007:

Other Income and Deductions, net	2009	2008	2007
	(Millions of Dollars)		
Carrying Costs	\$ -	\$0.8	\$28.8
Gain on Property Sales	1.7	2.3	12.9
AFUDC - Equity	15.9	7.5	5.1
Donations and Contributions	(5.5)	(12.0)	(10.3)
Other, net	13.7	11.3	5.2
Total Other Income and Deductions, net	\$25.8	\$9.9	\$41.7

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 our Oak Creek AQCS project. We expect to see an increase in AFUDC - Equity during 2010 with the continued construction of the Oak Creek AQCS project.

2008 vs. 2007: Other income and deductions, net decreased by \$31.8 million when compared to 2007. We stopped accruing carrying charges on regulatory assets as the January 2008 PSCW rate order allowed a current return on them. Additionally, in 2007 we recognized approximately \$12.9 million on property sales, most of which related to land sales in northern Wisconsin and the Upper Peninsula of Michigan, as compared to \$2.3 million in 2008.

Interest Expense, net

Interest Expense, net	2009	2008	2007
	(Millions of Dollars)		
Gross Interest Costs	\$106.9	\$89.6	\$94.8
Less: Capitalized Interest	6.6	3.0	1.8
Interest Expense, net	\$100.3	\$86.6	\$93.0

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.

During 2010, 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. As a result, we expect our net interest expense to increase in 2010.

2008 vs. 2007: Interest expense, net decreased by \$6.4 million in 2008 when compared with 2007. Our gross interest costs decreased by \$5.2 million because of lower short-term interest rates that were offset in part by higher short-term debt balances. Our capitalized interest increased by \$1.2 million primarily because of increased capital expenditures related to the Blue Sky Green Field wind project.

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

Income Taxes

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. For further information regarding income taxes, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2010 annual effective tax rate to range between 33.0% and 35.0%.

2008 vs. 2007: Our effective income tax rate was 37.6% in 2008 compared with 39.5% in 2007.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2009, 2008 and 2007:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
Cash Provided by (Used in)			
Operating Activities	\$226.6	\$362.9	\$213.8
Investing Activities	(\$333.6)	(\$212.7)	\$236.2
Financing Activities	\$96.9	(\$143.8)	(\$446.2)

Operating Activities

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 pension and post-retirement benefit plans. During 2009, we contributed \$283.8 million to Wisconsin Energy's benefit plans compared to \$37.9 million during 2008.

2008 vs. 2007: Cash provided by operating activities was \$362.9 million during 2008, which was \$149.1 million higher than 2007. The primary drivers of this increase were the increased amortizations of deferred costs associated with regulatory assets and lower tax payments.

During 2008, we experienced increased amortizations of deferred costs associated with regulatory assets. During 2008, our cash income taxes were \$326.9 million lower than 2007, primarily because of additional tax depreciation, increased deductions for contributions to Wisconsin Energy's pension plan for our employees and deferred taxes associated with the nuclear decommissioning trust assets. In accordance with IRS guidelines, we completed a review in 2008 and concluded that certain timing items that historically had been capitalized and depreciated for tax purposes could be deducted currently. Our January 2009 contribution to Wisconsin Energy's qualified pension plan resulted in a tax deduction for 2008.

Investing Activities

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. We expect to release approximately \$194.5 million of restricted cash during 2010 as we issue bill credits to our retail customers from the Point Beach proceeds.

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

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. During 2010, we expect our capital expenditures to increase because of the continued construction of the Oak Creek AQCS project and the start of construction of our recently approved Glacier Hills wind farm project. See Rates and Regulatory Matters - Oak Creek Air Quality Control System Approval and - Renewable Energy Portfolio under Factors Affecting Results, Liquidity and Capital Resources for additional information on the projects.

2008 vs. 2007: Cash used in investing activities was \$212.7 million compared to \$236.2 million provided by investing activities during 2007. This reflects a reduction in proceeds from asset sales and increased capital expenditures during 2008, partially offset by an increase in restricted cash from the sale of Point Beach released to us.

During 2008, we released \$345.1 million of restricted cash related to the Point Beach bill credits. In addition, our capital expenditures increased by \$42.7 million in 2008 primarily due to increased construction spending related to the completion of our Blue Sky Green Field wind project and the start of construction of the Oak Creek AQCS project.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2009	2008	2007
	(Millions of Dollars)		
Dividends to Wisconsin Energy	(\$179.6)	(\$367.0)	(\$179.6)
Capital Contribution from Wisconsin Energy	100.0	-	-
Increase (Reduction) in Total Debt	176.2	225.3	(271.9)
Other	0.3	(2.1)	5.3
Cash Provided by (Used in) Financing	<u>\$96.9</u>	<u>(\$143.8)</u>	<u>(\$446.2)</u>

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. For additional information on the debt issue and repurchase, see Note J -- Long Term Debt in the Notes to Consolidated Financial Statements.

2008 vs. 2007: Cash used in financing activities was \$143.8 million during 2008 as compared to \$446.2 million during 2007. During 2008, we issued \$550 million of debentures. The net proceeds were used to repay short-term debt and for other general corporate purposes, including the payment of a \$150 million special dividend to Wisconsin Energy to rebalance our capital structure for the impact of the sale of Point Beach.

CAPITAL RESOURCES AND REQUIREMENTS

Capital Resources

We anticipate meeting our capital requirements during 2010 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 2010, 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

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

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.

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, committed approximately \$23.6 million under our bank back-up credit facility. We have no current plans to replace Lehman's commitment. Excluding Lehman's commitment, as of December 31, 2009, we had approximately \$474.0 million of available, undrawn lines under our bank back-up credit facility. As of December 31, 2009, we had approximately \$92.0 million of commercial paper outstanding that was supported by the available lines of credit.

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, 2009:

<u>Total Facility *</u>	<u>Letters of Credit</u>	<u>Credit Available *</u>	<u>Facility Expiration</u>
(Millions of Dollars)			
\$476.4	\$2.4	\$474.0	March 2011

* Excludes Lehman's commitment

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:

<u>Capitalization Structure</u>	<u>2009</u>		<u>2008</u>	
	(Millions of Dollars)			
Common Equity	\$2,804.2	46.4%	\$2,582.8	46.7%
Preferred Stock	30.4	0.5%	30.4	0.6%
Long-Term Debt (a)	1,969.5	32.5%	1,885.3	34.1%
Capital Lease Obligations (a)	1,123.3	18.6%	1,001.1	18.1%
Short-Term Debt (b)	120.2	2.0%	29.6	0.5%
Total	<u>\$6,047.6</u>	<u>100.0%</u>	<u>\$5,529.2</u>	<u>100.0%</u>

(a) Includes current maturities

(b) Includes subsidiary note payable to Wisconsin Energy

We recorded a \$331.1 million capital lease in May 2008 in connection with the in-service date of PWGS 2. For additional information, see Note J -- Long-Term Debt in the Notes to Consolidated Financial Statements.

We recorded an increase of approximately \$1.0 billion to our capital lease obligation in connection with OC 1 being placed into service on February 2, 2010. See Note T -- Subsequent Events for additional information.

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, 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.

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

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and preferred stock by S&P, Moody's and Fitch as of December 31, 2009:

	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
Commercial Paper	A-2	P-1	F1
Secured Senior Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A

In July 2009, S&P affirmed our ratings and revised our ratings outlook from positive to stable.

In June 2009, Fitch affirmed our ratings and revised our ratings outlook from stable to negative.

Our ratings outlook assigned by Moody's is stable.

Subject to other factors affecting the credit markets as a whole, we believe these 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, but rather an indication of creditworthiness. 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. Each rating should be evaluated independently of any other rating.

Capital Requirements

Our estimated 2010, 2011 and 2012 capital expenditures are as follows:

<u>Capital Expenditures</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>
	(Millions of Dollars)		
Renewable	\$96.6	\$392.8	\$289.6
Environmental	301.7	170.6	69.2
Base Spending	337.6	371.6	379.1
Total	<u>\$735.9</u>	<u>\$935.0</u>	<u>\$737.9</u>

Changing environmental and other regulations such as air quality and renewable energy standards and electric reliability initiatives that impact us may cause actual future long-term capital requirements to vary from these estimates.

The anticipated increase in our capital expenditures is related to the Oak Creek AQCS project that is expected to be completed in 2012 and the Glacier Hills Wind Park that is also expected to be completed by 2012.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately \$923 million as of December 31, 2009. 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 plans due to poor investment returns during 2008. We do not expect to make contributions to the plans during 2010 as they are adequately funded. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note N -- Benefits in the Notes to Consolidated Financial Statements.

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

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, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For additional information, see Note O -- Guarantees in the Notes to Consolidated Financial Statements.

We have identified two tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of these two variable interest entities. The requested information required to make this determination has not been supplied. As a result, we do not consolidate these entities. We account for one of these contracts as a capital lease and for the other contract as an operating lease, and both are reflected in the Contractual Obligations/Commercial Commitments table below. For additional information, see Note F -- Variable Interest Entities in the Notes to Consolidated Financial Statements.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2009:

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)	\$4,001.8	\$111.1	\$222.1	\$792.8	\$2,875.8
Capital Lease Obligations (c)	4,163.2	177.6	359.2	365.1	3,261.3
Operating Lease Obligations (d)	76.0	21.3	36.6	8.4	9.7
Purchase Obligations (e)	13,040.5	1,103.8	1,338.1	822.5	9,776.1
Other Long-Term Liabilities (f)	75.0	74.3	0.7	-	-
Total Contractual Obligations	\$21,356.5	\$1,488.1	\$1,956.7	\$1,988.8	\$15,922.9

- (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 1, which was placed into service on February 2, 2010, see Note T -- 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 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 2010 supplemental executive retirement plan obligation. For additional information on employer contributions to Wisconsin Energy's benefit plans, see Note N -- Benefits in the Notes to Consolidated Financial Statements.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes. 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.

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

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 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. For information regarding the current 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.

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 2009, 2008 and 2007, as measured by degree days, may be found above in Results of Operations.

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

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, 2009. Borrowing levels under these arrangements vary from period to period depending on capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis at December 31, 2009 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2009, we had \$92.0 million of commercial paper outstanding with a weighted average interest rate of 0.19% 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 \$0.9 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 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, 2009 was approximately:

	<u>Millions of Dollars</u>
Pension trust funds	\$793.7
Other post-retirement benefits trust funds	\$129.3

The expected long-term rate of return on plan assets was 8.25% for both the pension and other post-retirement benefits for 2009. During 2009, we contributed \$265 million to Wisconsin Energy's pension plans, which brought the plans close to fully funded under the Pension Protection Act. As a result, we changed our asset mix to a higher weighting of fixed income securities and a lower weighting of equity securities. In 2010, our expected long-term rate of return on the pension plan assets is 7.25% reflecting the change in asset allocations. The lower expected return on plan assets will increase 2010 pension costs by approximately \$10 million; however, increased pension expense was considered in the rate setting process by the PSCW.

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.

Subsequent to its last asset/liability study completed in 2005, Wisconsin Energy has consulted with its investment advisors on an annual basis and requested them to 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.

Credit Ratings: 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 only in the event of a credit rating change to below investment grade. As of December 31, 2009, we estimate that the collateral or the termination payment required under these agreements totaled approximately \$191.0 million. In addition, we have commodity contracts that in the event of a credit rating downgrade could result in a reduction of our unsecured credit granted by counterparties.

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.

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

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.

POWER THE FUTURE

Under Wisconsin Energy's PTF strategy, we expect to meet a significant portion of our future generation needs through the leasing of the PWGS and the Oak Creek expansion. We are leasing the PWGS units and OC 1 from We Power under long-term leases, and we will recover the lease payments in our electric rates. When OC 2 goes into service, we expect to also recover those lease payments in our electric rates. Our lease payments are based on the cash costs authorized by our primary regulator to We Power.

The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2. The following tables identify 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

Unit Name	Scheduled In Service	Approximate Cash Costs (a)
OC 1	February 2010 (Actual)	\$ 1,346 million
OC 2	August 2010	\$ 670 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 Wisconsin Energy's ownership percentage.

Power the Future - Port Washington

Background: In December 2002, the PSCW issued a written order (the Port Order) granting a CPCN for the construction of PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of our existing 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.

Lease Terms: The PSCW approved the lease agreements and related documents under which we will staff, operate and maintain PWGS 1 and PWGS 2. Key terms of the leased generation contracts include:

- 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 Port Order, which do not include the key financial terms.

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

Power the Future - Oak Creek Expansion

Background: In November 2003, the PSCW issued an order (the Oak Creek Order) granting us, along with Wisconsin Energy and We Power, a CPCN to commence construction of two 615 MW coal-fired units (the Oak Creek expansion) to be located adjacent to the site of our existing Oak Creek Power Plant. OC 1 was placed into service on February 2, 2010. Bechtel is currently targeting commercial operation of OC 2 by the end of August 2010. The total cost for the two units, including the common facilities, was set at \$2.191 billion, and the order provided 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 an event of loss.

In June 2005, construction commenced at the site. In November 2005, Wisconsin Energy completed the sale of approximately a 17% interest in the two units to two unaffiliated entities who share ratably in the construction costs. Although these two unaffiliated entities have a combined ownership interest in approximately 17% of the MWs generated by the two units, they only have a 15% ownership interest in the Oak Creek expansion as a whole, taking into account the common facilities being constructed, including the coal handling and water intake systems.

The Oak Creek expansion includes a new coal handling system that will serve both the existing units at Oak Creek and OC 1 and OC 2. The new coal handling system was placed into service during the fourth quarter of 2007 at a cost of approximately \$199.1 million.

The Oak Creek expansion also includes a new water intake system that will serve both the existing units at Oak Creek and OC 1 and OC 2. The new water intake system was placed into service in January 2009 at a cost of approximately \$132.6 million.

Lease Terms: In October 2004, the PSCW approved the leased generation contracts between us and We Power for OC 1 and OC 2. Key terms of the leased generation contracts include:

- 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 with the potential for subsequent renewals at reduced rates;
- 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 Oak Creek Order, which do not include the key financial terms.

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

Bechtel's claims were based on the alleged impact of severe weather and certain labor-related matters, as well as the alleged effects of ERS-directed changes and delays allegedly caused by ERS prior to the issuance of the Full Notice to Proceed in July 2005. These claims, as well as claims submitted by ERS related to the rights of the parties under the construction contract and ERS counterclaims, had been submitted to binding arbitration.

Effective December 16, 2009, ERS and Bechtel entered into the Settlement Agreement that settled all claims between them regarding OC 1 and OC 2. Pursuant to the terms of this Settlement Agreement, ERS will pay to Bechtel \$72 million to settle these claims, with \$10 million already paid in 2009 and the remaining \$62 million to be paid in six additional installments upon the achievement of specific project milestones. In addition, Bechtel will

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

receive 120 days of schedule relief for OC 1 and 60 days for OC 2. Therefore, the guaranteed in-service date of September 29, 2009 for OC 1 was extended to January 27, 2010, and the guaranteed in-service date of September 29, 2010 for OC 2 was extended to November 28, 2010.

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

OC 1 was placed into service on February 2, 2010. Bechtel is currently targeting commercial operation of OC 2 by the end of August 2010.

The Settlement Agreement also provides for Bechtel's release of ERS from all matters related to Bechtel's claims, among other things, and for ERS' release of Bechtel from all matters related to ERS' claims that were subject to arbitration, among other things.

WPDES Permit: In July 2008, in order to resolve all outstanding challenges to the WPDES permit issued by the WDNR in connection with the Oak Creek expansion, we, along with the joint owners of the Oak Creek expansion, reached an agreement with Clean Wisconsin, Inc. and Sierra Club, the groups who were opposing the WPDES permit. Under the settlement agreement, these groups agreed to withdraw their opposition to the modified WPDES permit issued in July 2008 for the existing and expansion units at Oak Creek.

In the agreement with Clean Wisconsin, Inc. and Sierra Club, 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 implement 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 89% of our electric revenues are regulated by the PSCW, 5% 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. 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, 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 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.

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

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;
- 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 Downtown Milwaukee (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 return on equity from 10.75% to 10.4%.

The PSCW also made, among others, the following determinations:

- New depreciation rates are incorporated into the new base rates approved in the rate case;
- Certain regulatory assets currently scheduled to be fully amortized over the next four years are to instead be amortized over the next eight years; and
- We will continue to receive AFUDC on 100% of CWIP for the environmental control projects at our Oak Creek Power Plant and at Edgewater Generating Unit 5, and on the Glacier Hills Wind Park.

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 (9.5%), effective upon commercial operation of OC 1, which occurred on February 2, 2010. This rate increase is subject to refund with interest, depending upon the MPSC's final decision on our rate request, which is expected in July 2010.

2008 Wisconsin Rate Increase: During 2007, we initiated rate proceedings. On January 17, 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: On February 19, 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 is being driven primarily by increases in the price of natural gas, changes in the timing of plant outages and increased MISO costs. We expect to implement this rate request by the end of the first quarter of 2010, subject to refund based upon the PSCW's final decision. The ultimate rate increase will be subject to the review and approval of the PSCW, which we expect to receive by the end of 2010.

2009 Fuel Cost Decrease Filing: We operate under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity to our retail customers in Wisconsin. In April 2009,

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

based on three months of actual fuel cost data and nine months of projected data, we forecasted that our monitored fuel cost for 2009 would fall outside the range prescribed by the PSCW and would be less than the monitored fuel cost reflected in then authorized rates. Therefore, in April 2009, we filed a request with the PSCW to decrease annual Wisconsin retail electric rates by \$67.2 million for calendar year 2009. On April 30, 2009, the PSCW approved the fuel cost decrease filing with rates effective May 1, 2009.

2008 Fuel Recovery Request: In March 2008, we filed a rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel costs was being driven primarily by increases in the price of natural gas and the higher cost of transporting coal by rail as a result of increases in the cost of diesel fuel. On April 11, 2008, the PSCW approved an annual increase of \$76.9 million (3.3%) in Wisconsin retail electric rates on an interim basis. In July 2008, we received the final rate order, which authorized an additional \$42.0 million in rate increases, for a total increase of \$118.9 million (5.1%). Any over-collection of fuel surcharge revenue in calendar year 2008 was subject to refund with interest at a rate of 10.75%. In April 2009, the PSCW ordered that we should refund \$8.8 million (including interest) of over-collected fuel surcharge revenue. The refund was issued during the second quarter of 2009.

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 \$800 million (\$950 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. In addition, Public Act 295 calls for the implementation of a renewable portfolio standard of 10% 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.

Fuel Cost Adjustment Procedure: Within the state of Wisconsin, we operate under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts. Embedded within our base rates is an amount to recover fuel costs. Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are 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 are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis.

In June 2006, the PSCW opened a docket (01-AC-224) to consider revisions to the existing fuel rules (Chapter PSC 116). The current version of the revised rule recommends modifications to allow for annual plan and reconciliation filings of fuel costs by each regulated utility. In the period between plan and reconciliation, escrow accounting would be used to record fuel costs outside a plus or minus 2% annual band of the total fuel costs allowed in rates. The proposed rule further recommends that the escrow balance be trued-up annually following the end of each calendar year. Currently, draft legislation is under review. The earliest that we expect any possible action on the fuel rules is mid-2010.

Our electric operations in Michigan operate under a Power Supply Cost Recovery mechanism which generally allows for the recovery of fuel and purchased power costs on a dollar for dollar basis.

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

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, 2009, we had deferred \$157.8 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 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.

MISO Energy Markets: The PSCW approved deferral treatment for our costs related to the implementation of the MISO Energy Markets. Amounts deferred through December 31, 2007 are being recovered in rates. For additional information, see Industry Restructuring and Competition -- Electric Transmission and Energy Markets.

Wholesale Electric Pricing: In August 2006, we filed a wholesale rate case with FERC. The filing requested an annual increase in rates of approximately \$16.7 million applicable to four existing wholesale electric customers. This includes a mechanism for fuel and other cost adjustments. In November 2006, FERC approved the rate filing subject to refund with interest. Three of the existing customers' rates were effective in January 2007. The remaining wholesale customer's rates were effective in May 2007. FERC approved a settlement of the rate filing in September 2007. In August 2008, we issued a one-time \$62.5 million refund to our wholesale customers pursuant to a FERC-approved settlement related to the sale of Point Beach.

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 do not expect the new depreciation rates to 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%. 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. Assuming the bulk of additional renewables is wind generation, we must obtain approximately 362 MW of additional renewable capacity by 2012 and another approximately 300 MW of additional renewable capacity by 2015 to meet the requirements of Act 141. We have already started development of additional sources of renewable energy which will assist us in complying with Act 141. See Renewable Energy Portfolio discussion below.

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

In 2007, the Governor of Wisconsin established the Governor's Task Force on Global Warming. The Task Force issued its final report in July 2008 that included an increased renewable portfolio standard. Pursuant to the Task Force's recommendations, the renewable portfolio standard would increase to 10% by 2013, 20% by 2020 and 25% by 2025. Draft legislation regarding this recommendation, as well as other recommendations made by the Task Force, is pending in the Wisconsin legislature.

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 DOA back to the PSCW and/or contracted third parties. In addition, Act 141 requires that 1.2% of utilities' annual operating revenues be used to fund these programs. The Governor of Wisconsin's Task Force on Global Warming recommended in July 2008 that the energy efficiency goal be based on achieving efficiency resulting in a 2% reduction in electric load annually starting in 2015 rather than a goal based on a percent of revenue.

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. We entered into a conditional turbine agreement for the new wind facility and filed a revised, lower cost estimate with the PSCW in May 2009 of \$335.2 million to \$413.5 million, excluding AFUDC. The PSCW approved the CPCN in January 2010. We currently expect to install up to 90 wind turbines with generating capacity of up to approximately 207 MW, subject to turbine selection and the final site configuration. We expect 2012 to 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 sawdust 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 either the federal production tax credit or the federal 30% investment tax credit. We currently expect the plant to cost approximately \$250 million and to be completed during the fall of 2013, subject to regulatory approvals. We expect to file a request for a Certificate of Authority for the project in the first quarter of 2010.

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.

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

We had adequate capacity to meet all of our firm electric load obligations during 2009 and 2008. 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 2010. 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 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 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. The capital cost of implementing the EPA Consent Decree is estimated to be approximately \$1.2 billion over the 10 year period ending 2013. These costs are principally associated with the installation of air quality controls on Pleasant Prairie Units 1 and 2 and Oak Creek Units 5-8. In June 2007, we submitted an application to the PSCW requesting approval to construct environmental controls at Oak Creek Units 5-8 by 2012 as required by the Consent Decree. We expect the cost of completing this project to be approximately \$800 million, excluding AFUDC. Through December 31, 2009, we have spent approximately \$686 million associated with the installation of air quality controls and have retired four coal units as part of our plan under the Consent Decree. For further information concerning the Consent Decree, see Note R -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in this report.

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 SIPs 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 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 July 2009, Wisconsin issued both a draft Attainment Demonstration and a Redesignation request. Based on our review of these drafts, we do not believe we would be subject to any further requirements to reduce emissions. The EPA must take final approval action once Wisconsin finalizes its submittals.

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. Given this most recent revision, the EPA has delayed the deadline for new non-attainment area designations under the revised standard once it is finalized, from March 2010 to March 2011. Although it is likely that additional counties 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 existing coal-fired generation facilities.

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

Fine Particulate Standard: In December 2004, the EPA designated fine particulate (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 will now have three years 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 existing coal-fired generation facilities or Wisconsin Energy's new PTF generating units that we are leasing, including OC 1, OC 2, PWGS 1 and PWGS 2.

In a related matter, on February 11, 2010, the EPA announced its intent to end the transitional policy which has allowed facilities to use in their air permits PM₁₀ (an earlier measure of particulate matter) as a surrogate when measuring PM_{2.5} emissions. This policy had allowed both the agencies and permit holders to continue to use standards that were well established, until the EPA and the states developed the necessary tools for permitting PM_{2.5} emissions. The discontinuation of this policy creates uncertainty as to how this parameter will be evaluated when we seek and maintain Title V air permits for our facilities. The EPA will be taking written comments on the rule, and until the rule is finalized, we are not able to predict the impact of this policy change on our operations.

Sulfur Dioxide Standard: The EPA is currently in the process of revising the ambient air quality standard for SO₂. In November 2009, the EPA proposed to strengthen the primary standard for SO₂ by revoking the current standards and replacing them with a more stringent one-hour SO₂ standard. If the revised standard ultimately selected results in the designation of new non-attainment areas, it could potentially have an adverse effect on our facilities in those areas.

Clean Air Interstate Rule: The EPA issued the final CAIR in March 2005 to facilitate the states in meeting the 8-hour ozone and PM_{2.5} standards by addressing the regional transport of SO₂ and NO_x. CAIR required NO_x and SO₂ emission reductions in two phases from electric generating units located in a 28-state region within the eastern United States, including Wisconsin and Michigan. Overall, CAIR is expected to result in a 70% reduction in SO₂ emissions and a 65% reduction in NO_x emissions from 2002 emission levels. A final CAIR rule was adopted in Wisconsin and Michigan. 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. We previously determined that compliance with the NO_x and SO₂ emission reduction requirements under the Consent Decree would substantially mitigate costs to comply with CAIR and would achieve the levels necessary under at least the first phase of CAIR. It will be necessary to see what the revised rule contains before we can determine if any additional reductions will be required.

Mercury and Other Hazardous Air Pollutants: The EPA issued the final 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 MACT limits for fossil-fuel fired electric utilities 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. 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.

Wisconsin and Michigan State Only Mercury Rules: Both Wisconsin and Michigan now 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.

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

Clean Air Visibility Rule: The EPA issued CAVR in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to the EPA's CAIR. The pollutants from power plants that reduce visibility include PM_{2.5} or compounds that contribute to fine particulate formation, NO_x, 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 starts a two-year review window for the EPA to issue Federal Implementation Plans, unless a state submits and receives SIP approval.

Wisconsin and Michigan have completed the BART rules, which cover one aspect of 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 CAIR rule pursuant to a ruling by the U.S. Court of Appeals for the D.C. Circuit requiring it to do so.

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

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 a voluntary 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 proposals that would impose mandatory restrictions on CO₂ emissions continue to be considered in the U.S. Congress, 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 CWA requires that the location, design, construction and capacity of cooling water intake structures reflect the 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-

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

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.

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 addition, 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.

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

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

LEGAL MATTERS

Cash Balance Pension Plan: On June 30, 2009, a lawsuit was filed by 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 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. We believe the Plan correctly calculated the lump-sum distributions. An adverse outcome of this lawsuit could affect Plan funding and expense. We are currently unable to predict the final outcome or impact of this litigation.

Settlement with the Mines: In May 2007, we entered into a settlement agreement with our largest customers, two iron ore mines, related to an arbitration proceeding over disputed billings arising from the special negotiated contracts the mines operated under until they expired in December 2007. The settlement was a full and complete resolution of all claims and disputes between the parties for electric service rendered by us under the power purchase agreements through March 31, 2007. Pursuant to the settlement, the mines paid us approximately \$9.0 million and we released to the mines all funds we were holding in escrow. Beginning in January 2008, the mines began receiving electric service from us in accordance with tariffs approved by the MPSC.

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

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

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. We do not believe the lawsuit has merit and we will vigorously defend the case. This lawsuit is not expected to have a material adverse effect on our financial statements. In June 2007, another stray voltage lawsuit was settled. This settlement did not have a material adverse effect on our financial condition or results of operations. We continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Point Beach Nuclear Plant: We previously owned two electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. In September 2007, we sold Point Beach to an affiliate of FPL for approximately \$924 million. For additional information on this sale, see Corporate Strategy at the beginning of Management's Discussion and Analysis of Financial Condition and Results of Operations. A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, we are purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we are paying a predetermined price per MWh for energy delivered according to a schedule that is established in the agreement. Under the agreement, if our credit rating from either S&P or Moody's falls below investment grade, or if the holders of any indebtedness in excess of \$100.0 million accelerate or have the right to accelerate the maturity of such indebtedness as a result of a default, we would need to provide a parent guaranty or other form of collateral in the amount of \$100.0 million (escalating at 3% per year commencing in 2024).

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 Unit 1 and in March 2013 for Unit 2 before they were renewed by the NRC 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. We anticipate that the DOE will appeal this decision and that any recoveries will be included 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

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

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. These issues include:

- Addition of generating capacity in the state;
- Modifications to the regulatory process to facilitate development of merchant generating plants;
- Development of a regional independent electric transmission system operator;
- Improvements to existing and addition of new electric transmission lines in the state; and
- Addition of renewable generation.

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 territory in Michigan. We believe that this lack of alternate supplier activity reflects our small market area in Michigan, our competitive regulated power supply prices and a general lack of interest in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Electric Transmission and Energy Markets

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and a relatively new 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 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. In October 2009, FERC issued an order related to the allocation of costs for network transmission upgrades. As a condition of this order, MISO is expected to submit a filing by July 15, 2010 to replace the current cost allocation methodology.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of 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.

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

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 ARRs and FTRs. ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2009 through May 31, 2010. The resulting ARR valuation and the secured FTRs should adequately 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.

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

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, 2009, we had \$1,063.1 million in regulatory assets and \$812.1 million in regulatory liabilities. In the future, if we move to market based rates, or if the actions of our regulators change, we may conclude that we are unable to follow regulatory accounting. In this situation, 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.

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

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

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

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	\$4.2
0.5% decrease in expected rate of return on plan assets	\$4.4

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note N -- Benefits in the Notes to Consolidated Financial Statements). Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan

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

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

OPEB Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	\$2.3
0.5% decrease in health care cost trend rate in all future years	(\$2.7)
0.5% decrease in expected rate of return on plan assets	\$0.6

Unbilled Revenues: We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total operating revenues during 2009 of approximately \$3.3 billion included accrued revenues of \$212.8 million as of December 31, 2009.

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>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
Operating Revenues	\$ 3,288.3	\$ 3,410.1	\$ 3,321.6
Operating Expenses			
Fuel and purchased power	1,064.5	1,242.3	992.1
Cost of gas sold	389.7	526.4	441.9
Other operation and maintenance	1,231.7	1,295.2	1,041.9
Depreciation, decommissioning and amortization	265.1	256.0	269.7
Property and revenue taxes	99.1	96.4	91.7
Total Operating Expenses	<u>3,050.1</u>	<u>3,416.3</u>	<u>2,837.3</u>
Amortization of Gain	<u>230.7</u>	<u>488.1</u>	<u>6.5</u>
Operating Income	468.9	481.9	490.8
Equity in Earnings of Transmission Affiliate	51.9	45.4	37.9
Other Income and Deductions, net	25.8	9.9	41.7
Interest Expense, net	<u>100.3</u>	<u>86.6</u>	<u>93.0</u>
Income Before Income Taxes	446.3	450.6	477.4
Income Taxes	<u>157.7</u>	<u>169.3</u>	<u>188.5</u>
Net Income	288.6	281.3	288.9
Preferred Stock Dividend Requirement	<u>1.2</u>	<u>1.2</u>	<u>1.2</u>
Earnings Available for Common Stockholder	<u>\$ 287.4</u>	<u>\$ 280.1</u>	<u>\$ 287.7</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

	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Property, Plant and Equipment		
Electric	\$ 6,477.5	\$ 6,348.3
Gas	850.0	830.3
Steam	89.9	83.6
Common	239.1	236.5
Other	<u>61.5</u>	<u>61.6</u>
	7,718.0	7,560.3
Accumulated depreciation	<u>(2,822.6)</u>	<u>(2,721.2)</u>
	4,895.4	4,839.1
Construction work in progress	382.6	188.4
Leased facilities, net	<u>959.6</u>	<u>870.2</u>
Net Property, Plant and Equipment	6,237.6	5,897.7
Investments		
Restricted cash	-	172.4
Equity investment in transmission affiliate	276.7	243.1
Other	<u>0.5</u>	<u>0.4</u>
Total Investments	277.2	415.9
Current Assets		
Cash and cash equivalents	18.3	28.4
Restricted cash	194.5	214.1
Accounts receivable, net of allowance for doubtful accounts of \$31.5 and \$27.2	218.3	213.4
Accounts receivable from related parties	27.5	64.7
Accrued revenues	212.8	233.1
Materials, supplies and inventories	321.5	296.5
Prepayments	122.2	122.3
Regulatory assets	48.5	69.9
Other	<u>25.5</u>	<u>69.1</u>
Total Current Assets	1,189.1	1,311.5
Deferred Charges and Other Assets		
Regulatory assets	1,014.6	992.9
Other	<u>152.7</u>	<u>157.4</u>
Total Deferred Charges and Other Assets	1,167.3	1,150.3
Total Assets	<u>\$ 8,871.2</u>	<u>\$ 8,775.4</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

	2009	2008
	(Millions of Dollars)	
Capitalization		
Common equity	\$ 2,804.2	\$ 2,582.8
Preferred stock	30.4	30.4
Long-term debt	1,969.5	1,885.3
Capital lease obligations	1,111.3	991.8
Total Capitalization	5,915.4	5,490.3
Current Liabilities		
Long-term debt and capital lease obligations due currently	12.0	9.3
Short-term debt	92.0	-
Subsidiary note payable to Wisconsin Energy	28.2	29.6
Accounts payable	207.0	289.2
Accounts payable to related parties	79.9	76.2
Payroll and vacation accrued	64.9	65.4
Accrued taxes	50.5	9.6
Accrued interest	13.8	13.3
Regulatory liabilities	220.8	307.7
Other	100.3	124.0
Total Current Liabilities	869.4	924.3
Deferred Credits and Other Liabilities		
Regulatory liabilities	591.3	786.5
Deferred income taxes - long-term	833.8	691.7
Accumulated deferred investment tax credits	35.6	39.1
Asset retirement obligations	52.6	52.3
Pension and other benefit obligations	374.2	614.3
Other	198.9	176.9
Total Deferred Credits and Other Liabilities	2,086.4	2,360.8
Commitments and Contingencies (Note R)		
Total Capitalization and Liabilities	\$ 8,871.2	\$ 8,775.4

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

	2009	2008	2007
	(Millions of Dollars)		
Operating Activities			
Net income	\$ 288.6	\$ 281.3	\$ 288.9
Reconciliation to cash			
Depreciation, decommissioning and amortization	272.5	263.4	279.3
Amortization of gain	(230.7)	(488.1)	(6.5)
Equity in earnings of transmission affiliate	(51.9)	(45.4)	(37.9)
Distributions from transmission affiliate	40.9	34.2	29.2
Deferred income taxes and investment tax credits, net	132.3	264.6	8.9
Contributions to benefit plans	(283.8)	(37.9)	(23.2)
Change in - Accounts receivable and accrued revenues	51.2	(5.3)	8.3
Inventories	(25.0)	(10.9)	2.8
Other current assets	19.6	(44.9)	(2.9)
Accounts payable	(64.4)	45.2	19.7
Accrued income taxes, net	51.1	(61.5)	(154.7)
Deferred costs, net	46.2	81.5	(56.3)
Other current liabilities	4.9	9.6	(8.9)
Other, net	(24.9)	77.1	(132.9)
Cash Provided by Operating Activities	<u>226.6</u>	<u>362.9</u>	<u>213.8</u>
Investing Activities			
Capital expenditures	(481.1)	(523.7)	(481.0)
Investment in transmission affiliate	(22.7)	(22.2)	-
Proceeds from asset sales, net	1.8	7.1	938.8
Proceeds from liquidation of nuclear decommissioning trust	-	-	552.4
Change in restricted cash	192.0	345.1	(731.6)
Proceeds from investments within nuclear decommissioning trust	-	-	1,528.7
Other activity within nuclear decommissioning trust	-	-	(1,528.7)
Other, net	(23.6)	(19.0)	(42.4)
Cash (Used in) Provided by Investing Activities	<u>(333.6)</u>	<u>(212.7)</u>	<u>236.2</u>
Financing Activities			
Dividends paid on common stock	(179.6)	(367.0)	(179.6)
Dividends paid on preferred stock	(1.2)	(1.2)	(1.2)
Issuance of long-term debt	250.0	697.0	23.4
Retirement and repurchase of long-term debt	(164.4)	(147.0)	(345.4)
Change in total short-term debt	90.6	(324.7)	50.1
Capital contribution from parent	100.0	-	-
Other, net	1.5	(0.9)	6.5
Cash Provided by (Used in) Financing Activities	<u>96.9</u>	<u>(143.8)</u>	<u>(446.2)</u>
Change in Cash and Cash Equivalents	(10.1)	6.4	3.8
Cash and Cash Equivalents at Beginning of Year	<u>28.4</u>	<u>22.0</u>	<u>18.2</u>
Cash and Cash Equivalents at End of Year	<u>\$ 18.3</u>	<u>\$ 28.4</u>	<u>\$ 22.0</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

	2009	2008
	(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	802.4	688.8
Retained earnings	1,668.9	1,561.1
Total Common Equity	2,804.2	2,582.8
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	30.4	30.4
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	-
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	0.1
4.81% effective rate due 2030	2.0	2.0
Notes (unsecured)		
1.92% variable rate due 2015 (a)	-	17.4
0.504% variable rate due 2016 (b)	67.0	67.0
0.504% variable rate due 2030 (b)	80.0	80.0
Variable rate notes held by us (see Note J)	(147.0)	-
Unamortized discount, net	(17.6)	(16.2)
Total Long-Term Debt	1,969.5	1,885.3
Obligations Under Capital Leases (see Note J)	1,111.3	991.8
Total Capitalization	\$ 5,915.4	\$ 5,490.3

(a) Variable interest rate as of December 31, 2008.

(b) Variable interest rate as of December 31, 2009.

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, 2006	\$ 332.9	\$ 655.8	\$ 1,539.9	\$ 2,528.6
Net income			288.9	288.9
Other comprehensive income			-	-
Comprehensive Income	-	-	288.9	288.9
Cash dividends				
Common stock			(179.6)	(179.6)
Preferred stock			(1.2)	(1.2)
Stock-based compensation		10.8		10.8
Tax benefit of exercised stock options allocated from Parent		8.7		8.7
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	<u>\$ 332.9</u>	<u>\$ 802.4</u>	<u>\$ 1,668.9</u>	<u>\$ 2,804.2</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 wholly-owned 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 \$35.9 million as of December 31, 2009.

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.

Subsequent Events: We have evaluated and determined that no material events took place after our balance sheet date of December 31, 2009 through our financial statement issuance date of February 26, 2010, except as disclosed in Note T.

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

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules in Wisconsin allow us to request rate increases if fuel and purchased power costs exceed the band established by the PSCW. We are also required to reduce rates if fuel and purchased power costs fall below the band established by the PSCW.

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:

<u>Other Income and Deductions, net</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
Carrying Costs	\$ -	\$0.8	\$28.8
Gain on Property Sales	1.7	2.3	12.9
AFUDC - Equity	15.9	7.5	5.1
Donations and Contributions	(5.5)	(12.0)	(10.3)
Other, net	13.7	11.3	5.2
Total Other Income and Deductions, net	<u>\$25.8</u>	<u>\$9.9</u>	<u>\$41.7</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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

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 3.6% in 2009 and 2008, and 3.7% in 2007.

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 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 \$497.5 million as of December 31, 2009 and \$472.5 million as of December 31, 2008.

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 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. During 2007, we accrued AFUDC at a rate of 8.94%, as authorized by the PSCW in a prior rate order.

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:

	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
AFUDC - Debt	\$6.6	\$3.0	\$1.8
AFUDC - Equity	\$15.9	\$7.5	\$5.1

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

<u>Materials, Supplies and Inventories</u>	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Fossil Fuel	\$181.0	\$132.2
Materials and Supplies	99.3	93.1
Natural Gas in Storage	41.2	71.2
Total	<u>\$321.5</u>	<u>\$296.5</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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 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 L.

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, 2009, 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 I.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method. As of December 31, 2009 and 2008, we had a total ownership interest of approximately 23.0% in ATC. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note Q.

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

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.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 I.

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

	2009	2008	2007
Risk-free interest rate	0.3% - 2.5%	2.9% - 3.9%	4.7% - 5.1%
Dividend yield	3.0%	2.1%	2.2%
Expected volatility	25.9%	20.0%	13.0% - 20.0%
Expected life (years)	6.2	6.2	6.0
Expected forfeiture rate	2.0%	2.0%	2.0%
Pro forma weighted average fair value of stock options granted	\$8.01	\$9.39	\$8.72

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements: In September 2006, the FASB issued new accounting guidance relating to fair value measurements and also issued updated accounting guidance in 2008 and 2009. This guidance defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value, expands disclosures related to fair value measurements and was effective for financial statements issued for fiscal years beginning after November 15, 2007. This adoption did not have a significant financial impact on our financial condition, results of operations or cash flows. See Note M -- Fair Value Measurements for required disclosures.

Noncontrolling Interests in Consolidated Financial Statements: In December 2008, the FASB issued new accounting guidance relating to noncontrolling interests in consolidated financial statements. This guidance clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements and was effective for fiscal years beginning on or after December 15, 2008. We adopted these provisions effective January 1, 2009. This adoption did not have a material financial impact on our financial condition, results of operations or cash flows.

Disclosures about Derivative Instruments and Hedging Activities: In March 2008, the FASB issued new accounting guidance relating to derivative instruments and hedging activities. This guidance requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements, and was effective for fiscal years beginning after November 15, 2008. We adopted these provisions effective January 1, 2009. This adoption did not have any financial impact on our financial condition, results of operations or cash flows. See Note L -- Derivative Instruments for required disclosures.

Subsequent Events: In May 2009, the FASB issued new accounting guidance relating to management's assessment of subsequent events. This guidance clarifies that management must evaluate, as of each reporting period, events or transactions that occur after the balance sheet date through the date the financial statements are issued or are available to be issued, and was effective for interim and annual periods ending after June 15, 2009. We adopted these provisions effective June 30, 2009. This adoption had no financial impact on our financial condition, results of operations or cash flows.

Recognition and Presentation of Other-Than-Temporary Impairments: In April 2009, the FASB issued new accounting guidance that amended the other-than-temporary impairment guidance for debt securities to be more

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in financial statements. We adopted these provisions effective June 30, 2009. This adoption had no financial impact on our financial condition, results of operations or cash flows.

Amendments to Variable Interest Entity Consolidation Guidance: In June 2009, the FASB 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 is not expected to have any impact on our financial condition, results of operations or cash flows.

Employers' Disclosures about Post-retirement Benefit Plan Assets: In December 2008, the FASB issued new accounting guidance for employers' disclosures about plan assets of defined benefit pension or other post-retirement plans. This new guidance resulted in expanded disclosures related to post-retirement benefit plan assets and was effective for fiscal years ending after December 15, 2009. We adopted these provisions on December 31, 2009. This adoption had no impact on our financial condition, results of operations or cash flows. See Note N -- Benefits 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, 2009 and 2008, we had approximately \$12.4 million and \$20.0 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 should essentially be issued by the end of 2010.

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

	2009	2008
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	\$378.6	\$392.0
Deferred plant related -- capital leases	163.7	130.9
Escrowed electric transmission costs	157.8	199.0
Deferred unrecognized OPEB costs	77.9	48.7
Deferred income tax related	75.5	70.1
Deferred derivative amounts	11.6	57.0
Other, net	198.0	165.1
Total regulatory assets	<u>\$1,063.1</u>	<u>\$1,062.8</u>
Regulatory Liabilities		
Deferred cost of removal obligations	\$497.5	\$472.5
Deferred Point Beach related	202.4	431.5
Deferred income tax related	49.7	83.8
Other, net	62.5	106.4
Total regulatory liabilities	<u>\$812.1</u>	<u>\$1,094.2</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 (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, 2009, we have recorded \$44.8 million of environmental costs associated with manufactured gas plant sites as a regulatory asset, including \$9.3 million of deferrals for actual remediation costs incurred and a \$35.5 million accrual for estimated future site remediation (see Note R). In addition, we have deferred \$4.9 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 rate-making treatment.

As of December 31, 2009, we have \$16.0 million of 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 -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

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, which will become binding if we are unable to reach an agreement with a third party to sell our interest. We are continuing to negotiate with a third party to sell our interest in this unit. The completion of any sale will be subject to approval by the PSCW.

Point Beach: Prior to September 28, 2007, we owned two 518 MW electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. On September 28, 2007, we sold Point Beach to an affiliate of FPL for approximately \$924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel and associated inventories, and assumed the obligation to decommission the plant. We retained approximately \$506 million of the sales proceeds, which represents the net book value of the assets sold and certain transaction costs. In addition, we deferred the net gain on the sale of approximately \$418 million as a regulatory liability and deposited those proceeds into a restricted cash account. In connection with the sale, we also transferred \$390 million of decommissioning funds to the buyer. We then liquidated the balance of the decommissioning trust assets and retained approximately \$552 million of that cash. This cash was also placed into the restricted cash account. We are using the cash in the restricted cash account, and the interest earned on the balance, for the benefit of our customers and to pay certain taxes. Our regulators are directing the manner in which these proceeds will benefit customers. As of December 31, 2009, we have recorded a regulatory liability of approximately \$202.4 million that represents deferred gains that will be used for the benefit of our customers.

As of December 31, 2009, we have given approximately \$577.8 million in bill credits to our Wisconsin and Michigan retail customers and issued a refund of approximately \$62.5 million to wholesale customers in a one-time FERC-approved settlement. In addition, pursuant to the January 2008 PSCW rate order, during the first quarter of 2008, we used \$85.0 million of restricted cash proceeds to recover \$85.0 million of regulatory assets.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, we are purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we will be paying a predetermined price per MWh for energy delivered. Under the agreement, if our credit rating from either S&P or Moody's falls below investment grade, or if the holders of any indebtedness in excess of \$100.0 million accelerate or have the right to accelerate the maturity of such indebtedness as a result of a default, we would need to provide a parent guarantee or other form of collateral in the amount of \$100.0 million (escalating at 3% per year commencing in 2024). For further information regarding our former nuclear operations, see Note H.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)**E -- ASSET RETIREMENT OBLIGATIONS**

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

	<u>Balance at 12/31/08</u>	<u>Liabilities Incurred</u>	<u>Liabilities Settled</u> (Millions of Dollars)	<u>Accretion</u>	<u>Cash Flow Revisions</u>	<u>Balance at 12/31/09</u>
AROs	\$52.3	\$ -	(\$2.6)	\$2.9	\$ -	\$52.6

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 but have been unable to determine if we are the primary beneficiary of these two variable interest entities. The requested information required to make this determination has not been supplied. As a result, we do not consolidate these entities. We account for one of these contracts as a capital lease and the other contract as an operating lease. We have approximately \$417.9 million of required payments over the remaining terms of these two agreements, which expire over the next 13 years. We believe the required payments or any replacement power purchased will continue to be recoverable in rates. Total capacity and lease payments under these contracts in 2009, 2008 and 2007 were \$62.2 million, \$66.4 million and \$70.4 million, respectively.

G -- INCOME TAXES

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

<u>Income Taxes</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
	(Millions of Dollars)		
Current tax expense (benefit)	\$25.4	(\$95.3)	\$284.2
Deferred income taxes, net	135.8	270.5	(91.9)
Investment tax credit, net	(3.5)	(5.9)	(3.8)
Total Income Tax Expense	<u>\$157.7</u>	<u>\$169.3</u>	<u>\$188.5</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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	2009		2008		2007	
	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	\$155.8	35.0%	\$157.3	35.0%	\$166.7	35.0%
State income taxes net of federal tax benefit	22.5	5.0%	23.5	5.2%	24.5	5.1%
Domestic production activities deduction	(8.3)	(1.9%)	(7.9)	(1.8%)	-	- %
Production tax credits - wind	(7.1)	(1.6%)	(4.8)	(1.1%)	(0.1)	- %
Investment tax credit restored	(3.5)	(0.8%)	(5.9)	(1.3%)	(3.8)	(0.8%)
Other, net	(1.7)	(0.4%)	7.1	1.6%	1.2	0.2%
Total Income Tax Expense	<u>\$157.7</u>	<u>35.3%</u>	<u>\$169.3</u>	<u>37.6%</u>	<u>\$188.5</u>	<u>39.5%</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:

	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
<u>Deferred Tax Assets</u>		
Current		
Deferred gain	\$21.3	\$37.0
Employee benefits and compensation	10.7	11.0
Recoverable gas costs	0.6	0.2
Other	(1.2)	5.5
Total Current Deferred Tax Assets	<u>\$31.4</u>	<u>\$53.7</u>
Non-current		
Deferred revenues	\$270.8	\$204.5
Construction advances	111.9	105.7
Employee benefits and compensation	16.1	80.8
Deferred gain	-	27.2
Emission allowances	4.0	13.0
Other	(17.4)	(9.6)
Total Non-current Deferred Tax Assets	<u>\$385.4</u>	<u>\$421.6</u>
Total Deferred Tax Assets	<u><u>\$416.8</u></u>	<u><u>\$475.3</u></u>
<u>Deferred Tax Liabilities</u>		
Current		
Prepaid items	\$45.8	\$42.8
Uncollectible account expense	(4.0)	-
Total Current Deferred Tax Liabilities	<u>\$41.8</u>	<u>\$42.8</u>
Non-current		
Property-related	\$1,039.0	\$870.7
Employee benefits and compensation	-	80.4
Deferred transmission costs	63.2	76.4
Investment in transmission affiliate	80.1	52.2
Other	36.9	33.6
Total Non-current Deferred Tax Liabilities	<u>\$1,219.2</u>	<u>\$1,113.3</u>
Total Deferred Tax Liabilities	<u><u>\$1,261.0</u></u>	<u><u>\$1,156.1</u></u>
<u>Consolidated Balance Sheet Presentation</u>		
	<u>2009</u>	<u>2008</u>
Current Deferred Tax Asset (Liability)	(\$10.4)	\$10.9
Non-current Deferred Tax Asset (Liability)	(\$833.8)	(\$691.7)

Consistent with ratemaking 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:

	2009	2008
	(Millions of Dollars)	
Balance as of January 1	\$17.2	\$12.1
Additions based on tax positions related to the current year	0.9	-
Additions for tax positions of prior years	4.5	5.4
Reductions for tax positions of prior years	(1.2)	(0.3)
Reductions due to statute of limitations	-	-
Settlements during the period	-	-
Balance as of December 31	<u>\$21.4</u>	<u>\$17.2</u>

The amount of unrecognized tax benefits as of December 31, 2009 and 2008 excludes deferred tax assets related to uncertainty in income taxes of \$13.4 million and \$9.1 million, respectively. As of December 31, 2009 and 2008, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately \$8.1 million.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2009, 2008 and 2007, we recognized approximately \$1.4 million, \$1.7 million and \$1.1 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2009, 2008 and 2007, we recognized no penalties in the Consolidated Income Statements. We had approximately \$5.1 million and \$3.6 million of interest accrued in the Consolidated Balance Sheets as of December 31, 2009 and 2008, respectively.

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

Our primary tax jurisdictions include Federal and the state of Wisconsin. Currently, the tax years of 2004 through 2009 are subject to Federal and Wisconsin examination.

H -- NUCLEAR OPERATIONS

The sale of Point Beach was completed on September 28, 2007.

Nuclear Decommissioning: We recorded decommissioning expense in amounts equal to the amounts collected in rates and funded to the external trusts. Nuclear decommissioning costs were accrued over the expected service lives of the nuclear generating units and were included in electric rates. The decommissioning funding was \$11.2 million through September 2007. We liquidated our decommissioning trust assets as part of the sale of Point Beach.

I -- 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:

	2009	2008	2007
	(Millions of Dollars)		
Stock options	\$9.9	\$11.3	\$10.8
Performance units	12.9	8.7	5.0
Restricted stock	0.3	0.3	0.5
Share-based compensation expense	<u>\$23.1</u>	<u>\$20.3</u>	<u>\$16.3</u>
Related Tax Benefit	<u>\$9.3</u>	<u>\$8.1</u>	<u>\$6.6</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 2009:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2009	7,423,937	\$37.91		
Granted	1,129,315	\$42.22		
Exercised	(315,824)	\$26.05		
Forfeited	-			
Outstanding as of December 31, 2009	<u>8,237,428</u>	\$38.95	6.0	\$89.6
Exercisable as of December 31, 2009	<u>4,828,148</u>	\$33.95	4.6	\$76.7

We expect that substantially all of the outstanding options as of December 31, 2009 will be exercised.

In January 2010, the Compensation Committee awarded 257,350 Wisconsin Energy non-qualified stock options at an exercise price of \$49.84 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, 2009, 2008 and 2007 was \$5.9 million, \$6.9 million and \$22.7 million, respectively. Cash received by Wisconsin Energy from exercises of its options by our employees was \$8.2 million, \$8.0 million and \$27.5 million during the years ended December 31, 2009, 2008 and 2007, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately \$2.5 million, \$2.3 million and \$8.9 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, 2009:

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)
\$19.62 to \$31.07	1,186,103	\$26.27	3.0	1,186,103	\$26.27	3.0
\$33.44 to \$39.48	3,395,010	\$35.66	5.0	3,395,010	\$35.66	5.0
\$42.56 to \$48.04	3,656,315	\$46.12	8.0	247,035	\$47.27	7.3
	<u>8,237,428</u>	<u>\$38.95</u>	<u>6.0</u>	<u>4,828,148</u>	<u>\$33.95</u>	<u>4.6</u>

The following table summarizes information about non-vested Wisconsin Energy options held by our employees during 2009:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of January 1, 2009	3,339,669	\$8.81
Granted	1,129,315	\$8.01
Vested	(1,059,704)	\$7.59
Forfeited	-	
Non-Vested as of December 31, 2009	<u>3,409,280</u>	\$8.73

As of December 31, 2009, total compensation costs related to non-vested Wisconsin Energy stock options held by our employees and not yet recognized was approximately \$6.8 million, which is expected to be recognized over the next 16 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 2009:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2009	67,328	
Granted	-	
Released / Forfeited	(9,329)	\$28.47
Outstanding as of December 31, 2009	<u>57,999</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 2010, the Compensation Committee awarded 32,505 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 one-third of the award vesting on each anniversary of the grant date. During the vesting period, restricted share recipients also have voting rights and are entitled to dividends in the same manner as other shareholders.

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 \$0.4 million, \$1.1 million and \$1.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was \$0.2 million, \$0.3 million and \$0.7 million, respectively.

As of December 31, 2009, total compensation cost related to our share of Wisconsin Energy restricted stock not yet recognized was approximately \$0.6 million, which is expected to be recognized over the next 37 months on a weighted-average basis.

Performance Units: In January 2009, 2008 and 2007, the Compensation Committee awarded 309,310, 124,175 and 124,655 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, 2009, 2008 and 2007 had a total intrinsic value of \$9.3 million, \$7.9 million and \$4.7 million, respectively. The awards were subsequently distributed to our officers and key employees in January 2010, 2009 and 2008. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately \$3.2 million, \$2.9 million and \$1.6 million, respectively. As of December 31, 2009, total compensation cost related to performance units not yet recognized was approximately \$13.3 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

In January 2010, the Compensation Committee awarded 260,310 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

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 K 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)

J -- LONG-TERM DEBT

Debentures and Notes: As of December 31, 2009, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2010	\$0.1
2011	-
2012	-
2013	300.0
2014	300.0
Thereafter	1,387.0
Total	<u>\$1,987.1</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 purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 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.

During 2008, we issued \$550 million of debentures. The net proceeds were used to repay short-term debt and for other general corporate purposes, including the payment of a \$150 million special dividend to Wisconsin Energy.

Obligations Under Capital Leases

We are the obligor under a power purchase contract 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. Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately \$78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was \$149.0 million as of December 31, 2009 and will decrease to zero over the remaining life of the contract.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

PWGS: We are leasing PWGS 1 and PWGS 2, two 545 MW natural gas-fired generation units which were placed into 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 approximately \$127.2 million in the year 2021 for PWGS 1 and to approximately \$127.1 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 \$329.3 million and \$328.6 million, respectively, as of December 31, 2009 and will decrease to zero over the remaining lives of the contracts.

Oak Creek Expansion: We are leasing the common facilities, including the coal handling system which was placed into service in November 2007 and the water intake system which was placed into service in January 2009, from We Power under a PSCW approved lease. We recorded the leased plant and corresponding obligation at the estimated fair value of \$316.4 million. We are amortizing the leased plant on a straight-line basis over the 30-year term of the lease. The total obligation under the capital lease was \$316.4 million as of December 31, 2009 and will decrease to zero over the remaining life of the contract.

We paid the following lease payments during 2009, 2008 and 2007:

	2009	2008	2007
	(Millions of Dollars)		
Long-term power purchase commitment	\$29.1	\$28.1	\$27.1
PWGS 1	48.5	48.3	48.1
PWGS 2	48.9	29.7	-
OC Common Facilities	41.6	24.2	3.8
Total	\$168.1	\$130.3	\$79.0

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

Capital Lease Assets	2009	2008
	(Millions of Dollars)	
Long-term Power Purchase Commitment		
Under capital lease	\$140.3	\$140.3
Accumulated amortization	(69.8)	(64.1)
Total Long-term Power Purchase Commitment	<u>\$70.5</u>	<u>\$76.2</u>
PWGS 1		
Under capital lease	\$338.7	\$337.9
Accumulated amortization	(60.1)	(46.6)
Total PWGS 1	<u>\$278.6</u>	<u>\$291.3</u>
PWGS 2		
Under capital lease	\$331.1	\$331.1
Accumulated amortization	(21.3)	(8.1)
Total PWGS 2	<u>\$309.8</u>	<u>\$323.0</u>
OC Common Facilities		
Under capital lease	\$316.4	\$185.7
Accumulated amortization	(15.7)	(6.0)
Total OC Common Facilities	<u>\$300.7</u>	<u>\$179.7</u>
Total Leased Facilities	<u>\$959.6</u>	<u>\$870.2</u>

Future minimum lease payments under our capital leases and the present value of our net minimum lease payments as of December 31, 2009 are as follows:

Capital Lease Obligations	Power Purchase Commitment	PWGS 1	PWGS 2	OC Common Facilities	Total
2010	\$36.2	\$48.5	\$48.9	\$44.0	\$177.6
2011	37.5	48.5	48.9	44.0	178.9
2012	38.9	48.5	48.9	44.0	180.3
2013	40.4	48.5	48.9	44.0	181.8
2014	41.9	48.5	48.9	44.0	183.3
Thereafter	174.0	755.7	898.8	1,432.8	3,261.3
Total Minimum Lease Payments	<u>368.9</u>	<u>998.2</u>	<u>1,143.3</u>	<u>1,652.8</u>	<u>4,163.2</u>
Less: Estimated Executory Costs	(87.2)	-	-	-	(87.2)
Net Minimum Lease Payments	<u>281.7</u>	<u>998.2</u>	<u>1,143.3</u>	<u>1,652.8</u>	<u>4,076.0</u>
Less: Interest	(132.7)	(668.9)	(814.7)	(1,336.4)	(2,952.7)
Present Value of Net					
Minimum Lease Payments	149.0	329.3	328.6	316.4	1,123.3
Less: Due Currently	(7.1)	(3.0)	(1.9)	-	(12.0)
Total Capital Lease Obligations	<u>\$141.9</u>	<u>\$326.3</u>	<u>\$326.7</u>	<u>\$316.4</u>	<u>\$1,111.3</u>

We recorded an increase of approximately \$1.0 billion to our capital lease obligation in connection with OC 1 being placed into service on February 2, 2010. See Note T -- Subsequent Events for additional information.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

K -- SHORT-TERM DEBT

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

	2009		2008	
	Balance	Interest Rate	Balance	Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial Paper	\$92.0	0.19%	\$ -	- %

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

	2009	2008
	(Millions of Dollars, except for percentages)	
Maximum Commercial Paper Outstanding	\$437.5	\$452.5
Average Commercial Paper Outstanding	\$248.8	\$283.3
Weighted-Average Interest Rate	0.27%	2.71%

We have entered into a 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%.

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, committed approximately \$23.6 million under our bank back-up credit facility. We have no current plans to replace Lehman's commitment. Excluding Lehman's commitment, as of December 31, 2009, we had approximately \$474.0 million of available, undrawn lines under our bank back-up credit facility. Our bank back-up credit facility expires in March 2011, but may be renewed for two one-year extensions, subject to lender approval. As of December 31, 2009, we had approximately \$92.0 million of commercial paper outstanding that was supported by the available lines of credit, and our subsidiary had a \$28.2 million note payable to Wisconsin Energy with a weighted average interest rate of 4.59%.

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, 2009, we were in compliance with all covenants.

L -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers. 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, 2009, we

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

recognized \$11.6 million in regulatory assets and \$9.3 million in regulatory liabilities related to derivatives in comparison to \$57.0 million in regulatory assets and \$11.8 million in regulatory liabilities as of December 31, 2008.

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 \$0.8 million is recorded in Other deferred charges and other assets, and the long-term portion of our derivative liabilities of \$2.6 million is recorded in Other deferred credits and other liabilities. Our Consolidated Balance Sheet as of December 31, 2009 includes:

	Derivative Asset	Derivative Liability
	(Millions of Dollars)	
Natural Gas	\$1.2	\$6.6
Fuel Oil	0.6	-
FTRs	5.8	-
Coal	2.1	-
Total	\$9.7	\$6.6

Our Consolidated Income Statements include gains (losses) on derivative instruments used in our risk management strategies for those commodities supporting our electric operations and natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the year ended December 31, 2009 were as follows:

	Volume	Gains (Losses)
		(Millions of Dollars)
Natural Gas	45.2 million Dth	(\$70.9)
Energy	23,520 MWh	(0.5)
Fuel Oil	6.8 million gallons	(2.5)
FTRs	27,262 MW	12.9
Total		(\$61.0)

As of December 31, 2009, we have posted collateral of \$6.6 million in our margin accounts.

M -- FAIR VALUE MEASUREMENTS

Fair value measurements require enhanced disclosures about assets and liabilities that are measured and reported at fair value and establish a hierarchical 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 ongoing 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 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, 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	\$195.1	\$3.3	\$5.8	\$204.2
Liabilities:				
Derivatives	\$4.2	\$2.4	\$ -	\$6.6
Total	\$4.2	\$2.4	\$ -	\$6.6

Recurring Fair Value Measures	As of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Cash Equivalents	\$8.0	\$ -	\$ -	\$8.0
Restricted Cash	386.5	-	-	386.5
Derivatives	-	4.1	8.8	12.9
Total	\$394.5	\$4.1	\$8.8	\$407.4
Liabilities:				
Derivatives	\$34.0	\$15.3	\$ -	\$49.3
Total	\$34.0	\$15.3	\$ -	\$49.3

Cash Equivalents consist of certificates of deposit and money market funds. 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

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

	2009	2008
	(Millions of Dollars)	
Balance as of January 1	\$8.8	\$13.0
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	(3.0)	(4.2)
Transfers in and/or out of Level 3	-	-
Balance as of December 31	<u>\$5.8</u>	<u>\$8.8</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 L -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

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

Financial Instruments	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	\$30.4	\$20.2	\$30.4	\$19.0
Long-term debt including current portion	\$1,987.1	\$2,088.2	\$1,901.5	\$1,896.3

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

N -- BENEFITS

Pensions and Other Post-retirement Benefits: We 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.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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	
	2009	2008	2009	2008
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	\$967.0	\$988.0	\$254.6	\$262.3
Service cost	21.4	17.0	8.2	9.8
Interest cost	61.9	60.4	16.5	15.9
Plan participants' contributions	-	-	6.2	-
Plan amendments	0.2	5.1	(9.3)	-
Actuarial loss (gain)	42.2	(28.4)	43.5	(27.2)
Gross benefits paid	(100.1)	(75.1)	(16.5)	(7.3)
Federal subsidy on benefits paid	N/A	N/A	0.9	1.1
Benefit Obligation at December 31	<u>\$992.6</u>	<u>\$967.0</u>	<u>\$304.1</u>	<u>\$254.6</u>
Change in Plan Assets				
Fair Value at January 1	\$510.7	\$719.4	\$97.0	\$126.9
Actual earnings (loss) on plan assets	113.9	(177.2)	20.8	(33.6)
Employer contributions	269.2	43.6	21.8	11.0
Plan participants' contributions	-	-	6.2	-
Gross benefits paid	(100.1)	(75.1)	(16.5)	(7.3)
Fair Value at December 31	<u>\$793.7</u>	<u>\$510.7</u>	<u>\$129.3</u>	<u>\$97.0</u>
Net Liability	<u>\$198.9</u>	<u>\$456.3</u>	<u>\$174.8</u>	<u>\$157.6</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	
	2009	2008	2009	2008
	(Millions of Dollars)			
Other deferred charges	\$ -	\$ -	\$0.5	\$0.4
Other long-term liabilities	198.9	456.3	175.3	158.0
Net liability	<u>\$198.9</u>	<u>\$456.3</u>	<u>\$174.8</u>	<u>\$157.6</u>

The accumulated benefit obligation for all the defined benefit plans was \$978.9 million and \$947.6 million as of December 31, 2009 and 2008, 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	
	2009	2008	2009	2008
	(Millions of Dollars)			
Net actuarial loss	\$355.9	\$367.3	\$104.7	\$78.6
Prior service costs (credits)	17.8	19.8	(19.2)	(22.6)
Transition obligation	-	-	1.0	1.3
Total	<u>\$373.7</u>	<u>\$387.1</u>	<u>\$86.5</u>	<u>\$57.3</u>

The following table shows the estimated amounts that will be amortized as a component of net periodic benefit costs during 2010:

	Pension	OPEB
	(Millions of Dollars)	
Net actuarial loss	\$18.2	\$8.1
Prior service costs (credits)	2.1	(11.8)
Transition obligation	-	0.3
Total	<u>\$20.3</u>	<u>(\$3.4)</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:

	2009	2008
	(Millions of Dollars)	
Projected benefit obligation	\$992.6	\$967.0
Accumulated benefit obligation	\$978.9	\$947.6
Fair value of plan assets	\$793.7	\$510.7

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

	Pension			OPEB		
	2009	2008	2007	2009	2008	2007
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	\$21.4	\$17.1	\$26.6	\$8.2	\$9.8	\$10.6
Interest cost	61.9	60.4	60.9	16.5	15.9	15.2
Expected return on plan assets	(73.0)	(60.7)	(61.0)	(8.9)	(10.9)	(9.5)
Amortization of:						
Transition obligation	-	-	-	0.3	0.3	0.3
Prior service cost (credit)	2.1	2.4	5.4	(12.6)	(12.6)	(12.5)
Actuarial loss	12.8	10.1	13.1	5.5	4.6	5.4
Net Periodic Benefit Cost	<u>\$25.2</u>	<u>\$29.3</u>	<u>\$45.0</u>	<u>\$9.0</u>	<u>\$7.1</u>	<u>\$9.5</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

	Pension			OPEB		
	2009	2008	2007	2009	2008	2007
<u>Weighted-Average assumptions used to determine benefit obligations as of Dec. 31</u>						
Discount rate	6.05%	6.50%	6.05%	5.75%	6.50%	6.10%
Rate of compensation increase	4.0	4.0	4.5 to 5.0	N/A	N/A	N/A
<u>Weighted-Average assumptions used to determine net cost for year ended Dec. 31</u>						
Discount rate	6.50%	6.05%	5.75%	6.50%	6.10%	5.75%
Expected return on plan assets	8.25	8.5	8.5	8.25	8.5	8.5
Rate of compensation increase	4.0	4.5 to 5.0	4.5 to 5.0	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)				7.5/20	7.5/9	8/11
Rate that the cost trend rate gradually adjusts to				5	5	5
Year that the rate reaches the rate it is assumed to remain at (Pre 65 / Post 65)				2015/2016	2014	2014

The expected long-term rate of return on plan assets was 8.25% in 2009, and 8.5% in 2008 and 2007. Subsequent to its last asset/liability study in 2005, Wisconsin Energy has consulted with its investment advisors on an annual basis and requested them to 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	\$26.7	(\$22.4)
Total of service and interest cost components	\$3.6	(\$2.9)

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 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 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 asset allocation is 45% equity investments and 55% fixed income investments. The current OPEB 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 Pension Trust assets as of December 31, 2009 by asset category within the fair value hierarchy (for further level information, see Note M):

Asset Category - Pension	Level 1	Level 2	Level 3	Total
		(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	\$600.6	\$193.1	\$ -	\$793.7

- (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 following table summarizes the fair value of our share of OPEB plan assets as of December 31, 2009 by asset category within the fair value hierarchy:

Asset Category - OPEB	Level 1	Level 2	Level 3	Total
		(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	\$81.5	\$47.8	\$ -	\$129.3

- (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.

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, 2009, the Pension Trust and OPEB plan assets included our share of approximately \$25.2 million of commercial paper issued by Wisconsin Energy, which represents less than 10% of total assets of the plan.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Cash Flows:

<u>Employer Contributions</u>	<u>Pension</u>	<u>OPEB</u>
	(Millions of Dollars)	
2007	\$24.6	\$11.5
2008	\$43.6	\$11.0
2009	\$269.2	\$21.8

Of the amounts listed above, we contributed approximately \$265 million, \$37.9 million and \$19.1 million to the qualified pension plan during 2009, 2008 and 2007, respectively. We do not expect to make contributions to the plan in 2010.

Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

The entire contribution to the OPEB plans during 2009 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:

<u>Year</u>	<u>Pension</u>	<u>Gross OPEB</u>	<u>Expected Medicare Part D Subsidy</u>
	(Millions of Dollars)		
2010	\$73.6	\$15.3	(\$0.7)
2011	\$88.5	\$16.5	(\$0.5)
2012	\$93.3	\$17.5	-
2013	\$94.4	\$19.7	-
2014	\$98.3	\$21.1	-
2015-2019	\$457.1	\$121.6	-

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, \$13.3 million and \$9.9 million during 2009, 2008 and 2007, respectively.

O -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties. As of December 31, 2009, we had the following guarantees:

<u>Maximum Potential Future Payments</u>	<u>Outstanding</u>	<u>Liability Recorded</u>
	(Millions of Dollars)	
\$2.9	\$0.1	\$ -

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

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was \$10.8 million as of December 31, 2009.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

P -- SEGMENT REPORTING

We are a wholly-owned 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.

Summarized financial information concerning our reportable operating segments for the years ended December 31, 2009, 2008 and 2007 is shown in the following table:

Year Ended	Reporting Operating Segments				Total
	Electric	Gas	Steam	Other (a)	
	(Millions of Dollars)				
<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
<u>December 31, 2007</u>					
Operating Revenues (b)	\$2,674.6	\$611.9	\$35.1	\$ -	\$3,321.6
Depreciation, Decommissioning and Amortization	\$234.9	\$31.1	\$3.7	\$ -	\$269.7
Operating Income (c)	\$423.7	\$61.2	\$5.9	\$ -	\$490.8
Equity in Earnings of Transmission Affiliate	\$37.9	\$ -	\$ -	\$ -	\$37.9
Capital Expenditures	\$440.8	\$38.2	\$2.0	\$ -	\$481.0
Total Assets (d)	\$7,469.2	\$669.2	\$58.7	\$115.7	\$8,312.8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

- (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.

Q -- 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, the Oak Creek coal handling system, the Oak Creek Water Intake System and the other generating facilities being constructed under Wisconsin Energy's PTF strategy, and we sell electric energy to an affiliated utility, Edison Sault. 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, 2009, 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 generating units being constructed as part of Wisconsin Energy's PTF strategy. ATC will reimburse us for these costs when new generation is placed into service. As of December 31, 2009 and 2008, we had a receivable of \$1.1 million and \$32.6 million, respectively, for these items.

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

	2009	2008	2007
	(Millions of Dollars)		
Operating Revenues	\$521.5	\$466.6	\$408.0
Operating Income	\$291.2	\$257.6	\$209.8
Net Income	\$213.4	\$188.0	\$154.1
Current Assets	\$51.1	\$50.8	\$48.3
Non-Current Assets	\$2,767.3	\$2,480.0	\$2,189.0
Current Liabilities	\$285.5	\$252.0	\$317.1
Non-Current Liabilities	\$1,336.5	\$1,229.6	\$1,007.6

Nuclear Management Company: Prior to the Point Beach sale, our former affiliate, WEC Nuclear Corporation, had a partial ownership in NMC, which held the operating licenses of Point Beach. Upon the sale of Point Beach, the operating licenses were transferred to the buyer, the relationship with NMC was terminated and WEC Nuclear Corporation was dissolved.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

We provided and received services from the following associated companies during 2009, 2008 and 2007:

Company	2009	2008	2007
	(Millions of Dollars)		
<u>Affiliate</u>			
Net Services Provided			
-We Power (excluding lease payments)	\$1.2	\$1.3	\$3.0
-Wisconsin Gas	\$58.2	\$51.3	\$50.8
-Edison Sault (including electric energy sold)	\$38.2	\$35.3	\$29.3
-Other	\$1.1	\$1.7	\$1.7
Net Services Received			
-We Power (lease payments)	\$347.0	\$312.2	\$223.7
-Wisconsin Energy	\$15.8	\$12.6	\$8.3
<u>Equity Investee</u>			
Services Provided			
-ATC	\$22.3	\$20.0	\$17.1
Services Received			
-ATC	\$196.0	\$194.4	\$172.1
-NMC	\$ -	\$ -	\$50.6

As of December 31, 2009 and 2008, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2009	2008
	(Millions of Dollars)	
Services Provided		
-ATC	\$1.1	\$2.1
Services Received		
-ATC	\$16.3	\$16.2

R -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2010 capital expenditures. During 2010, we estimate that total capital expenditures will be approximately \$736 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 2014. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases, including leases for vehicles and coal cars.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

	<u>(Millions of Dollars)</u>
2010	\$21.3
2011	21.5
2012	15.1
2013	5.5
2014	2.9
Thereafter	9.7
Total	<u>\$76.0</u>

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-ash disposal sites. We perform ongoing assessments of our manufactured gas plant sites and related disposal sites, as well as our coal ash 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 impacted by historical manufactured gas plant activities. Based upon ongoing analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from \$25 to \$45 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, 2009, we have established reserves of \$35.5 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.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our coal combustion by-products. However, some coal-ash by-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. The costs of these efforts are recovered under our fuel clause and are expensed as incurred. During 2009, 2008 and 2007, we incurred \$0.3 million, \$1.3 million and \$0.8 million, respectively, in coal-ash remediation expenses. As of December 31, 2009, we have no reserves established related to ash 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, 2009, we have spent approximately \$686 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Cash Balance Pension Plan: On June 30, 2009, a lawsuit was filed by 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 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. We believe the Plan correctly calculated the lump-sum distributions. An adverse outcome of this lawsuit could affect Plan funding and expense. We are currently unable to predict the final outcome or impact of this litigation.

S -- SUPPLEMENTAL CASH FLOW INFORMATION

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. During the year ended December 31, 2007, we paid \$92.9 million in interest, net of amounts capitalized, and \$327.5 million in income taxes, net of refunds.

As of December 31, 2009, 2008 and 2007, the amount of accounts payable related to capital expenditures was \$8.1 million, \$22.3 million and \$73.0 million, respectively.

T -- SUBSEQUENT EVENTS

On February 2, 2010, OC 1 was placed into service. Prior to December 31, 2009, certain common facilities associated with the Oak Creek facility were placed into service. We now have care, custody and control of OC 1 and will operate and maintain it over the 30 year life of the lease. As a result of the commercial operation of OC 1, in February 2010, we recorded an additional capital lease asset and capital lease obligation related to the Oak Creek expansion totaling approximately \$1.0 billion. We also expect that the additional lease payments for the Oak Creek expansion will total approximately \$4.5 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, 2009 and 2008, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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 26, 2010

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

None.

ITEM 9AT. 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 Securities Exchange Act of 1934, as amended (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, 2009.

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 temporary 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 2009 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 29, 2010 (the "2010 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 wholly-owned 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 WEPCO's Compensation Policies and Practices" and "Certain Relationships and Related Transactions - Compensation Committee Interlocks and Insider Participation" in the 2010 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 2010 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?" and "Certain Relationships and Related Transactions" in the 2010 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 2010 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

Consolidated Income Statements for the three years ended December 31, 2009.

Consolidated Balance Sheets at December 31, 2009 and 2008.

Consolidated Statements of Cash Flows for the three years ended December 31, 2009.

Consolidated Statements of Capitalization at December 31, 2009 and 2008.

Consolidated Statements of Common Equity for the three years ended December 31, 2009.

Notes to Consolidated Financial Statements.

Report of Independent Registered Public Accounting Firm.

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

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2009.

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, 2009	\$27.2	\$29.0	\$8.6	(\$33.3)	\$31.5	
December 31, 2008	\$21.9	\$28.4	\$5.2	(\$28.3)	\$27.2	
December 31, 2007	\$20.2	\$16.6	\$9.5	(\$24.4)	\$21.9	

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

By /s/GALE E. KLAPPA

Gale E. Klappa, Chairman of the Board, President
and Chief Executive Officer

Date: February 26, 2010

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 26, 2010
<u>/s/ALLEN L. LEVERETT</u> Allen L. Leverett, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	February 26, 2010
<u>/s/STEPHEN P. DICKSON</u> Stephen P. Dickson, Vice President and Controller -- Principal Accounting Officer	February 26, 2010
<u>/s/JOHN F. BERGSTROM</u> John F. Bergstrom, Director	February 26, 2010
<u>/s/BARBARA L. BOWLES</u> Barbara L. Bowles, Director	February 26, 2010
<u>/s/PATRICIA W. CHADWICK</u> Patricia W. Chadwick, Director	February 26, 2010
<u>/s/ROBERT A. CORNOG</u> Robert A. Cornog, Director	February 26, 2010
<u>/s/CURT S. CULVER</u> Curt S. Culver, Director	February 26, 2010
<u>/s/THOMAS J. FISCHER</u> Thomas J. Fischer, Director	February 26, 2010
<u>/s/ULICE PAYNE, JR.</u> Ulice Payne, Jr., Director	February 26, 2010
<u>/s/FREDERICK P. STRATTON, JR.</u> Frederick P. Stratton, Jr., Director	February 26, 2010

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

EXHIBIT INDEX
to
Annual Report on Form 10-K
For the year ended December 31, 2009

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.)

<u>Number</u>	<u>Exhibit</u>
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)

<u>Number</u>	<u>Exhibit</u>
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*	Credit Agreement, dated as of March 30, 2006, among Wisconsin Electric Power Company, as Borrower, the Lenders identified therein, and U.S. Bank National Association, as Administrative Agent and Fronting Bank. (Exhibit 10.2 to Wisconsin Energy Corporation's 06/30/09 Form 10-Q (File No. 001-09057).)
10.5*	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.

EXHIBIT INDEX - (Cont'd)

<u>Number</u>	<u>Exhibit</u>
10.6*	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).)
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 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.
10.14*	Wisconsin Energy Corporation Amended and Restated 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.
10.15*	Service Agreement, 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).)
10.16*	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 10.21 to Wisconsin Energy Corporation's 12/31/09 Form 10-K (File No. 001-09057)).** See Note.

EXHIBIT INDEX - (Cont'd)

<u>Number</u>	<u>Exhibit</u>
10.18*	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.
10.19*	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.
10.20*	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).)
10.21*	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.
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.

EXHIBIT INDEX - (Cont'd)

<u>Number</u>	<u>Exhibit</u>
10.30*	Wisconsin Energy Corporation Death Benefit Only Plan, amended and restated as of December 3, 2009. (Exhibit 10.34 to Wisconsin Energy Corporation's 12/31/09 Form 10-K (File No. 001-09057).)** See Note.
10.31*	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.
10.32*	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.
10.33*	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.
10.34*	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.
10.35*	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.
10.36*	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.
10.37*	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.
10.38*	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.
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.)

EXHIBIT INDEX - (Cont'd)

<u>Number</u>	<u>Exhibit</u>
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.

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.

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.