

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549**

FORM 10-Q

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

For the Quarterly Period Ended **June 30, 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

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 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer <input type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input checked="" type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input type="checkbox"/>

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2009):

Common Stock, \$10 Par Value,	33,289,327 shares outstanding.
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All of the common stock of Wisconsin Electric Power Company is owned by Wisconsin Energy Corporation.

WISCONSIN ELECTRIC POWER COMPANY

FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 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

ERS	Elm Road Services, LLC
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Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission

Environmental Terms

ANPR	Advanced Notice of Proposed Rulemaking
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
CWA	Clean Water Act
NAAQS	National Ambient Air Quality Standards
NO _x	Nitrogen Oxide
PM _{2.5}	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

Other Terms and Abbreviations

AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors of Wisconsin Energy

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:

CPCN	Certificate of Public Convenience and Necessity
Energy Policy Act	Energy Policy Act of 2005
ERISA	Employee Retirement Income Security Act of 1974
FNTP	Full Notice to Proceed
FTRs	Financial Transmission Rights
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Markets
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	<i>Power the Future</i>
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MW	Megawatt(s) (One MW equals one million watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits
SFAS	Statement of Financial Accounting Standards

Accounting Pronouncements

FIN 46(R)	Consolidation of Variable Interest Entities (Revised 2003)
FSP SFAS 107-1	Interim Disclosures about Fair Value of Financial Instruments
FSP SFAS 115-2	Recognition and Presentation of Other-Than-Temporary Impairments
FSP SFAS 132(R)-1	Employers' Disclosures about Post-retirement Benefit Plan Assets
FSP SFAS 157-2	Effective Date of SFAS 157
FSP SFAS 157-4	Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly
SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 160	Noncontrolling Interests in Consolidated Financial Statements
SFAS 161	Disclosures about Derivative Instruments and Hedging Activities
SFAS 165	Subsequent Events
SFAS 167	Amendments to FIN 46(R)

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" 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 implementation of 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.

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

- 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.
- Factors which may affect successful implementation of the settlement agreement with the two parties who were challenging the WPDES permit for the Oak Creek expansion.
- 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.
- Impacts of the significant contraction in the global credit markets affecting 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 our Annual Report on Form 10-K for the year ended December 31, 2008.

Wisconsin Electric Power Company expressly disclaims any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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 1,114,700 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 460,200 gas customers in Wisconsin and approximately 470 steam customers in metropolitan Milwaukee, Wisconsin. For further financial information about our business segments, see Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 8 -- Segment Information in the Notes to Consolidated Condensed Financial Statements in this report.

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 and in our 2008 Annual Report on Form 10-K. We have combined common functions with Wisconsin Gas and operate under the trade name of "We Energies."

Other: Bostco is our non-utility subsidiary that develops and invests in real estate. As of June 30, 2009, Bostco had \$36.3 million of assets.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC. We have condensed or omitted some information and note disclosures normally included in financial statements prepared in accordance with GAAP pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2008 Annual Report on Form 10-K, including the financial statements and notes therein.

PART I -- FINANCIAL INFORMATION**ITEM 1. FINANCIAL STATEMENTS**

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
	(Millions of Dollars)			
Operating Revenues	\$ 723.7	\$ 782.0	\$ 1,712.1	\$ 1,767.9
Operating Expenses				
Fuel and purchased power	253.7	298.6	519.8	636.9
Cost of gas sold	42.3	80.2	259.5	317.3
Other operation and maintenance	304.6	315.6	625.0	658.0
Depreciation, decommissioning and amortization	66.1	63.4	132.0	125.2
Property and revenue taxes	24.9	24.4	49.8	48.6
Total Operating Expenses	691.6	782.2	1,586.1	1,786.0
Amortization of Gain	55.1	87.0	119.3	246.0
Operating Income	87.2	86.8	245.3	227.9
Equity in Earnings of Transmission Affiliate	12.7	10.7	25.2	20.8
Other Income, net	6.4	4.7	12.3	13.4
Interest Expense, net	25.2	19.4	50.8	42.2
Income Before Income Taxes	81.1	82.8	232.0	219.9
Income Taxes	29.6	30.6	81.7	83.8
Net Income	51.5	52.2	150.3	136.1
Preferred Stock Dividend Requirement	0.3	0.3	0.6	0.6
Earnings Available for Common Stockholder	\$ 51.2	\$ 51.9	\$ 149.7	\$ 135.5

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited)	
	<u>June 30, 2009</u>	<u>December 31, 2008</u>
	(Millions of Dollars)	
<u>Assets</u>		
Property, Plant and Equipment		
In service	\$ 7,654.3	\$ 7,560.3
Accumulated depreciation	(2,787.0)	(2,721.2)
	<u>4,867.3</u>	<u>4,839.1</u>
Construction work in progress	280.9	188.4
Leased facilities, net	965.8	870.2
Net Property, Plant and Equipment	<u>6,114.0</u>	<u>5,897.7</u>
Investments		
Restricted cash	109.9	172.4
Equity investment in transmission affiliate	258.3	243.1
Other	0.4	0.4
Total Investments	<u>368.6</u>	<u>415.9</u>
Current Assets		
Cash and cash equivalents	10.2	28.4
Restricted cash	173.5	214.1
Accounts receivable	217.3	213.4
Accounts receivable from related parties	54.7	64.7
Accrued revenues	146.4	233.1
Materials, supplies and inventories	277.0	296.5
Prepayments	111.8	122.3
Regulatory assets	84.0	69.9
Other	47.3	69.1
Total Current Assets	<u>1,122.2</u>	<u>1,311.5</u>
Deferred Charges and Other Assets		
Regulatory assets	967.7	992.9
Other	135.0	157.4
Total Deferred Charges and Other Assets	<u>1,102.7</u>	<u>1,150.3</u>
Total Assets	<u>\$ 8,707.5</u>	<u>\$ 8,775.4</u>
<u>Capitalization and Liabilities</u>		
Capitalization		
Common equity	\$ 2,649.0	\$ 2,582.8
Preferred stock	30.4	30.4
Long-term debt	1,885.5	1,885.3
Capital lease obligations	1,102.7	991.8
Total Capitalization	<u>5,667.6</u>	<u>5,490.3</u>
Current Liabilities		
Long-term debt and capital lease obligations due currently	10.6	9.3
Short-term debt	223.5	-
Subsidiary note payable to Wisconsin Energy	29.3	29.6
Accounts payable	203.4	289.2
Accounts payable to related parties	76.1	76.2
Accrued taxes	77.8	9.6
Regulatory liabilities	236.8	307.7
Other	160.0	202.7
Total Current Liabilities	<u>1,017.5</u>	<u>924.3</u>
Deferred Credits and Other Liabilities		
Regulatory liabilities	718.0	786.5
Deferred income taxes - long-term	705.6	691.7
Pension and other benefit obligations	339.5	614.3
Other	259.3	268.3
Total Deferred Credits and Other Liabilities	<u>2,022.4</u>	<u>2,360.8</u>
Total Capitalization and Liabilities	<u>\$ 8,707.5</u>	<u>\$ 8,775.4</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
	2009	2008
	(Millions of Dollars)	
Operating Activities		
Net income	\$ 150.3	\$ 136.1
Reconciliation to cash		
Depreciation, decommissioning and amortization	137.0	132.0
Amortization of gain	(119.3)	(246.0)
Equity in earnings of transmission affiliate	(25.2)	(20.8)
Distributions from transmission affiliate	20.0	16.2
Deferred income taxes and investment tax credits, net	6.4	113.7
Contributions to benefit plans	(283.8)	(37.9)
Change in -		
Accounts receivable and accrued revenues	80.6	44.4
Inventories	19.5	41.9
Other current assets	18.1	12.1
Accounts payable	(73.5)	14.4
Accrued income taxes, net	73.2	(31.3)
Deferred costs, net	23.1	56.6
Other current liabilities	(6.5)	15.9
Other, net	(8.4)	73.3
Cash Provided by Operating Activities	11.5	320.6
Investing Activities		
Capital expenditures	(242.2)	(262.2)
Investment in transmission affiliate	(10.1)	(8.2)
Change in restricted cash	103.1	154.1
Other, net	(13.8)	(5.5)
Cash Used in Investing Activities	(163.0)	(121.8)
Financing Activities		
Dividends paid on common stock	(89.8)	(108.5)
Dividends paid on preferred stock	(0.6)	(0.6)
Retirement and repurchase of long-term debt	-	(147.0)
Change in short-term debt	223.2	49.6
Other, net	0.5	0.8
Cash Provided by (Used in) Financing Activities	133.3	(205.7)
Change in Cash and Cash Equivalents	(18.2)	(6.9)
Cash and Cash Equivalents at Beginning of Period	28.4	22.0
Cash and Cash Equivalents at End of Period	\$ 10.2	\$ 15.1

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

WISCONSIN ELECTRIC POWER COMPANY
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(Unaudited)

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8, Financial Statements and Supplementary Data, in our 2008 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary to a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and six months ended June 30, 2009 are not necessarily indicative of the results which may be expected for the entire fiscal year 2009 because of seasonal and other factors.

Subsequent Events: We have evaluated and determined that no material events took place after our balance sheet date of June 30, 2009 through our financial statement issuance date of August 4, 2009.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements: In September 2006, the FASB issued SFAS 157. SFAS 157 defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value, and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We partially adopted the provisions of SFAS 157 effective January 1, 2008. We adopted the provisions of FSP SFAS 157-2 effective January 1, 2009 and the provisions of FSP SFAS 157-4 effective April 1, 2009. The adoption of SFAS 157 did not have a significant financial impact on our financial condition, results of operations or cash flows. See Note 4 -- Fair Value Measurements for required disclosures.

Noncontrolling Interests in Consolidated Financial Statements: In December 2008, the FASB issued SFAS 160. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. This statement 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. We adopted the provisions of SFAS 160 effective January 1, 2009. The adoption of SFAS 160 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 SFAS 161, which amends SFAS 133. SFAS 161 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. SFAS 161 is effective for fiscal years beginning after November 15, 2008. We adopted the provisions of SFAS 161 effective January 1, 2009. The adoption of SFAS 161 did not have any financial impact on our financial condition, results of operations or cash flows. See Note 5 -- Derivative Instruments for required disclosures.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Subsequent Events: In May 2009, the FASB issued SFAS 165. SFAS 165 provides guidance on management's assessment of subsequent events. This statement 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. SFAS 165 is effective for interim and annual periods ending after June 15, 2009. We adopted the provisions of SFAS 165 effective June 30, 2009. The adoption of SFAS 165 had no material financial impact on our financial condition, results of operations or cash flows.

Interim Disclosures about Fair Value of Financial Instruments: In April 2009, the FASB issued FSP SFAS 107-1, which requires disclosures about the fair value of financial instruments for interim reporting periods of publicly traded companies as well as in financial statements. We adopted the provisions of FSP SFAS 107-1 effective June 30, 2009. The adoption of FSP SFAS 107-1 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 FSP SFAS 115-2, which amends the other-than-temporary impairment guidance for debt securities to be more operational and to improve the presentation and disclosure of the other-than-temporary impairments on debt and equity securities in financial statements. We adopted FSP SFAS 115-2 effective June 30, 2009. The adoption of FSP SFAS 115-2 had no material 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 SFAS 167, which amends certain requirements of FIN 46(R). The purpose of this standard is to improve financial reporting by enterprises with variable interest entities. SFAS 167 is effective for all new and existing variable interest entities for fiscal years beginning after November 15, 2009. We expect to adopt SFAS 167 on January 1, 2010.

Employers' Disclosures about Post-retirement Benefit Plan Assets: In December 2008, the FASB issued FSP SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other post-retirement plan. FSP SFAS 132(R)-1 will result in expanded disclosures related to post-retirement benefit plan assets and is effective for fiscal years ending after December 15, 2009. We expect to adopt FSP SFAS 132(R)-1 on December 31, 2009.

3 -- COMMON EQUITY

Share-Based Compensation Expense: For a description of share-based compensation, including Wisconsin Energy stock options, restricted stock and performance units, see Note H -- Common Equity in our 2008 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards classified as equity, 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 outstanding Wisconsin Energy stock options held by our employees during the period.

PART I -- FINANCIAL INFORMATION -- (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 and directors:

	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
	(Millions of Dollars)			
Stock options	\$2.6	\$2.6	\$4.9	\$5.4
Performance units	0.1	1.6	3.5	2.7
Restricted stock	0.1	0.1	0.2	0.2
Share-based compensation expense	<u>\$2.8</u>	<u>\$4.3</u>	<u>\$8.6</u>	<u>\$8.3</u>
Related Tax Benefit	<u>\$1.1</u>	<u>\$1.7</u>	<u>\$3.4</u>	<u>\$3.3</u>

Stock Option Activity: During the first six months of 2009, the Compensation Committee granted 1,129,315 Wisconsin Energy stock options to our employees that had an estimated fair value of \$8.01 per share. During the first six months of 2008, the Compensation Committee granted 1,266,645 Wisconsin Energy stock options to our employees that had an estimated fair value of \$9.39 per share. The following assumptions were used to value the Wisconsin Energy options using a binomial option pricing model:

	2009	2008
Risk-free interest rate	0.3% - 2.5%	2.9% - 3.9%
Dividend yield	3.0%	2.1%
Expected volatility	25.9%	20.0%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	6.2	6.2

The risk-free interest rate is based on the U.S. Treasury interest rate whose term is consistent with the expected life of the stock options. Dividend yield, expected volatility, expected forfeiture rate and expected life assumptions are based on Wisconsin Energy's historical experience.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

The following is a summary of our employees' Wisconsin Energy stock option activity for the three and six months ended June 30, 2009:

Stock Options	Number of Options	Weighted- Average Exercise Price	Weighted- Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2009	8,506,935	\$38.55		
Granted	-	\$ -		
Exercised	(29,904)	\$27.08		
Forfeited	-	\$ -		
Outstanding as of June 30, 2009	8,477,031	\$38.59		
Outstanding as of January 1, 2009	7,423,937	\$37.91		
Granted	1,129,315	\$42.22		
Exercised	(76,221)	\$25.79		
Forfeited	-	\$ -		
Outstanding as of June 30, 2009	8,477,031	\$38.59	6.4	\$37.8
Exercisable as of June 30, 2009	5,016,356	\$33.46	5.0	\$37.8

The intrinsic value of Wisconsin Energy options exercised by our employees was \$0.3 million and \$1.2 million for the three and six months ended June 30, 2009, and \$3.2 million and \$4.2 million for the same periods in 2008, respectively. Cash received by Wisconsin Energy from exercises of their options by our employees was \$2.0 million and \$4.9 million for the six months ended June 30, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises during the same periods was approximately \$0.5 million and \$1.2 million, respectively.

The following table summarizes information about Wisconsin Energy stock options held by our employees that were outstanding as of June 30, 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	1,369,609	\$25.87	3.4	1,369,609	\$25.87	3.4
\$33.44 to \$39.48	3,451,107	\$35.66	5.5	3,451,107	\$35.66	5.5
\$42.22 to \$48.04	3,656,315	\$46.12	8.5	195,640	\$47.80	7.7
	8,477,031	\$38.59	6.4	5,016,356	\$33.46	5.0

PART I -- FINANCIAL INFORMATION -- (Cont'd)

The following table summarizes information about our employees' non-vested Wisconsin Energy stock options during the six months ended June 30, 2009. There was no activity related to non-vested stock options during the second quarter.

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	(1,008,309)	\$7.55
Forfeited	-	\$ -
Non-vested as of June 30, 2009	3,460,675	\$8.72

As of June 30, 2009, our total compensation costs related to non-vested Wisconsin Energy stock options not yet recognized was approximately \$11.9 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restricted Shares: The Compensation Committee has also approved Wisconsin Energy restricted stock grants to certain of our key employees. The following restricted stock activity related to our employees occurred during the three and six months ended June 30, 2009:

Restricted Shares	Number of Shares	Weighted- Average Grant Date Fair Value
Outstanding as of April 1, 2009	65,853	
Granted	-	
Released / Forfeited	(3,951)	\$25.31
Outstanding as of June 30, 2009	61,902	
Outstanding as of January 1, 2009	67,328	
Granted	-	
Released / Forfeited	(5,426)	\$27.07
Outstanding as of June 30, 2009	61,902	

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. We also adjust expense for acceleration of vesting due to achievement of performance goals. The intrinsic value of Wisconsin Energy restricted stock vesting and held by our employees was \$0.1 million and \$0.2 million for the three and six months ended June 30, 2009, and \$0.6 million and \$1.0 million for the same periods in 2008, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was \$0.1 million for the three and six months ended June 30, 2009, and \$0.2 million for the same periods in 2008, respectively.

As of June 30, 2009, total compensation cost related to our share of Wisconsin Energy restricted stock not yet recognized was approximately \$0.7 million, which is expected to be recognized over the next 41 months on a weighted-average basis.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Performance Units: In January 2009 and 2008, the Compensation Committee granted 309,310 and 124,175 Wisconsin Energy performance units, respectively, to our officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of Wisconsin Energy's stock over a three year period. We are accruing our share of compensation costs over the three year period based on our estimate of the final expected value of the awards. Wisconsin Energy performance units earned as of December 31, 2008 and 2007 vested and were settled during the first quarter of 2009 and 2008, and had a total intrinsic value of \$7.8 million and \$4.7 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately \$2.9 million and \$1.6 million, respectively. As of June 30, 2009, total compensation cost related to performance units not yet recognized was approximately \$14.2 million, which is expected to be recognized over the next 26 months on a weighted-average basis.

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. See Note H -- Common Equity in our 2008 Annual Report on Form 10-K for additional information on these and other restrictions.

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

Comprehensive Income: Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners. During the six months ended June 30, 2009 and 2008, total comprehensive income was equal to net income.

4 -- FAIR VALUE MEASUREMENTS

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

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

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.

PART I -- FINANCIAL INFORMATION -- (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 June 30, 2009			Total
	Level 1	Level 2	Level 3	
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$283.4	\$ -	\$ -	\$283.4
Derivatives	0.1	2.4	15.4	17.9
Total	<u>\$283.5</u>	<u>\$2.4</u>	<u>\$15.4</u>	<u>\$301.3</u>
Liabilities:				
Derivatives	\$22.0	\$2.8	\$ -	\$24.8
Total	<u>\$22.0</u>	<u>\$2.8</u>	<u>\$ -</u>	<u>\$24.8</u>

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

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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

Quarter to Date	2009	2008
	(Millions of Dollars)	
Balance as of April 1	\$2.9	\$4.5
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	12.5	16.8
Transfers in and/or out of Level 3	-	-
Balance as of June 30	\$15.4	\$21.3
Change in unrealized gains (losses) relating to instruments still held as of June 30	\$ -	\$ -
Year to Date	2009	2008
	(Millions of Dollars)	
Balance as of January 1	\$8.8	\$13.0
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	6.6	8.3
Transfers in and/or out of Level 3	-	-
Balance as of June 30	\$15.4	\$21.3
Change in unrealized gains (losses) relating to instruments still held as of June 30	\$ -	\$ -

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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 5 -- 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	June 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	\$30.4	\$19.3	\$30.4	\$19.0
Long-term debt including current portion	\$1,901.5	\$1,931.3	\$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.

5 -- DERIVATIVE INSTRUMENTS

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. 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 June 30, 2009, we recognized \$37.1 million in regulatory assets and \$17.8 million in regulatory liabilities related to derivatives.

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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

We record our current derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative assets of \$0.2 million is recorded in Other deferred charges and other assets and the long-term portion of our derivative liabilities of \$2.2 million is recorded in Other deferred credits and other liabilities. Our Consolidated Condensed Balance Sheet as of June 30, 2009 includes:

	Derivative Asset	Derivative Liability
	(Millions of Dollars)	
Natural Gas	\$ -	\$24.8
Fuel Oil	0.1	-
FTRs	15.4	-
Coal	2.4	-
Total	<u>\$17.9</u>	<u>\$24.8</u>

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under Fuel and purchased power for those commodities supporting our electric operations and under Cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the three and six months ended June 30, 2009 were as follows:

	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	12.3 million Dth	(\$21.4)	23.5 million Dth	(\$38.6)
Energy	3,200 MWh purchased	(0.1)	15,120 MWh purchased	(0.6)
Fuel Oil	1.7 million gallons	(0.9)	3.0 million gallons	(1.8)
FTRs	6,710 MW	3.9	14,571 MW	4.8
Total		<u>(\$18.5)</u>		<u>(\$36.2)</u>

The aggregate fair value of all derivative instruments that are in a liability position as of June 30, 2009 is \$24.8 million, for which we have posted collateral of \$27.7 million in the normal course of business.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**6 -- BENEFITS**

The components of our net periodic pension and OPEB costs for the three and six months ended June 30, 2009 and 2008 were as follows:

Benefit Plan Cost Components	Pension Benefits		OPEB	
	2009	2008	2009	2008
	(Millions of Dollars)			
Three Months Ended June 30				
Net Periodic Benefit Cost				
Service cost	\$5.5	\$4.1	\$2.0	\$2.4
Interest cost	15.4	15.5	4.1	3.8
Expected return on plan assets	(18.3)	(15.0)	(2.2)	(2.7)
Amortization of:				
Transition obligation	-	-	-	0.1
Prior service cost (credit)	0.5	0.7	(3.1)	(3.2)
Actuarial loss	3.0	2.8	1.4	0.9
Net Periodic Benefit Cost	<u>\$6.1</u>	<u>\$8.1</u>	<u>\$2.2</u>	<u>\$1.3</u>
Six Months Ended June 30				
Net Periodic Benefit Cost				
Service cost	\$10.7	\$8.5	\$4.1	\$4.9
Interest cost	30.9	30.2	8.3	7.9
Expected return on plan assets	(36.5)	(30.3)	(4.5)	(5.4)
Amortization of:				
Transition obligation	-	-	0.1	0.2
Prior service cost (credit)	1.1	1.2	(6.3)	(6.3)
Actuarial loss	6.4	5.1	2.8	2.2
Net Periodic Benefit Cost	<u>\$12.6</u>	<u>\$14.7</u>	<u>\$4.5</u>	<u>\$3.5</u>

In January 2009, we contributed \$283.8 million to Wisconsin Energy's benefit plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. In January 2009, the committee that oversees the investment of the pension assets authorized the Plan Trustee to invest in the commercial paper of Wisconsin Energy. As of June 30, 2009, the Pension Trust held approximately \$89 million of commercial paper issued by Wisconsin Energy.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**7 -- GUARANTEES**

We enter into various guarantees to provide financial and performance assurance to third parties. As of June 30, 2009, we had the following guarantees:

<u>Maximum Potential Future Payments</u>	<u>Outstanding</u> (Millions of Dollars)	<u>Liability Recorded</u>
\$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 \$12.2 million as of June 30, 2009 and \$13.0 million as of December 31, 2008.

8 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable operating segments for the three and six months ended June 30, 2009 and 2008 is shown in the following table:

	<u>Reportable Operating Segments</u>			<u>Total</u>
	<u>Electric</u>	<u>Gas</u>	<u>Steam</u>	
<u>Three Months Ended</u>	(Millions of Dollars)			
June 30, 2009				
Operating Revenues (a)	\$644.2	\$72.3	\$7.2	\$723.7
Operating Income (Loss)	\$86.0	\$1.4	(\$0.2)	\$87.2
June 30, 2008				
Operating Revenues (a)	\$663.2	\$110.8	\$8.0	\$782.0
Operating Income (Loss)	\$86.5	\$0.7	(\$0.4)	\$86.8
<u>Six Months Ended</u>				
June 30, 2009				
Operating Revenues (a)	\$1,329.9	\$359.8	\$22.4	\$1,712.1
Operating Income	\$200.8	\$39.2	\$5.3	\$245.3
June 30, 2008				
Operating Revenues (a)	\$1,323.6	\$421.0	\$23.3	\$1,767.9
Operating Income	\$179.1	\$42.9	\$5.9	\$227.9

(a) We account for all intersegment revenues at tariff rates established by the PSCW. Intersegment revenues were not material.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**9 -- 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. Instead, we account for one of these contracts as a capital lease and the other contract as an operating lease. We have approximately \$446.2 million of required payments over the remaining terms of these two agreements, which expire over the next 14 years. We believe the required payments or any replacement power purchased will continue to be recoverable in rates. Total capacity and minimum lease payments under these contracts for the periods ended June 30, 2009 and December 31, 2008 were \$30.1 million and \$66.4 million, respectively.

10 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters: We periodically review our exposure for remediation costs as evidence becomes available indicating that our liability has changed. Given current information, 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.

Indemnifications: In connection with the sale of Point Beach, we agreed to provide the buyer with indemnification provisions customary to transactions involving the sale of nuclear assets.

11 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2009, we paid \$50.0 million in interest, net of amounts capitalized, and \$0.6 million in income taxes, net of refunds. During the six months ended June 30, 2008, we paid \$40.1 million in interest, net of amounts capitalized, and \$0.5 million in income taxes, net of refunds.

As of June 30, 2009 and 2008, the amount of accounts payable related to capital expenditures was \$9.9 million and \$5.1 million, respectively.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2009

EARNINGS

We had net income of \$51.5 million for the second quarter of 2009, a decrease of \$0.7 million, or 1.3%, from the second quarter of 2008. A more detailed analysis of our financial results follows.

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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Electric Utility Revenues and Sales**

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2009 with the second quarter of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

Electric Utility Operations	Three Months Ended June 30					
	Electric Revenues			MWh Sales		
	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$228.0	\$10.6	\$217.4	1,841.8	4.9	1,836.9
Small Commercial/Industrial	209.6	(6.4)	216.0	2,050.2	(116.7)	2,166.9
Large Commercial/Industrial	144.0	(26.5)	170.5	2,151.1	(613.2)	2,764.3
Other - Retail	4.9	-	4.9	36.6	(0.5)	37.1
Total Retail	586.5	(22.3)	608.8	6,079.7	(725.5)	6,805.2
Wholesale - Other	27.1	(7.9)	35.0	306.9	(346.5)	653.4
Resale - Utilities	5.8	(2.8)	8.6	214.5	97.3	117.2
Other Operating	24.8	14.0	10.8	-	-	-
Total	\$644.2	(\$19.0)	\$663.2	6,601.1	(974.7)	7,575.8
Weather -- Degree Days (a)						
Heating (954 Normal)				946	(16)	962
Cooling (167 Normal)				134	25	109

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

Our electric utility operating revenues decreased by \$19.0 million, or approximately 2.9%, when compared to the second quarter of 2008. Our total electric sales volumes decreased by approximately 12.9% as compared to the second quarter of 2008. Total retail sales volumes declined nearly 10.7%, almost all of which relates to retail sales volumes to our small and large commercial and industrial customers. The primary reason for the reduced sales volumes relates to a continued decline in economic conditions during the second quarter of 2009 as compared to the same period in 2008.

For the remainder of 2009, we expect to see a continued decline in electric sales to commercial and industrial customers as compared to 2008 as a result of the downturn in the economy. In April 2009, the PSCW approved our request to decrease our Wisconsin retail electric rates for calendar year 2009 due to a decrease in fuel and purchased power costs. We also expect to continue to see a reduction in revenues as a result of this approval, which is expected to reduce revenues by approximately \$45.8 million for calendar year 2009. For more information on the fuel cost decrease filing, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

We estimate that the decrease in electric revenue was offset in part by an increase of \$31.9 million as a result of fewer bill credits to our customers from the sale of Point Beach during the second quarter of 2009 as compared to the same period in 2008. For more information on bill credits, see Amortization of Gain in Results of Operations -- Three Months Ended June 30, 2009.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Our electric revenues were \$10.0 million higher in the second quarter of 2009 as compared to 2008 because of a one-time entry related to MISO RSG credits that was not made in the second quarter of 2008. The second quarter entry reversed a first quarter charge to revenues. During the first quarter of 2009, the PSCW ordered us to refund \$10.0 million of anticipated RSG credits that we hoped to receive from MISO in 2009. As discussed in the Form 10-Q for the first quarter of 2009, we reduced our revenues by \$10.0 million because of the PSCW order. We did not record a receivable for the anticipated RSG credits because we believed that the ultimate recovery of the credits from MISO was uncertain. In the second quarter of 2009, the FERC issued a notice that significantly reduced the amount of RSG credits we hoped to receive from MISO. As a result of the FERC ruling, we requested and received an order from the PSCW that allowed us to record a regulatory asset for RSG credits that we refunded to customers that we do not ultimately expect to receive from MISO. The PSCW order allowed us to reverse the \$10.0 million charge to revenues that we recorded in the first quarter of 2009. For further information on the RSG credits, see Factors Affecting Results, Liquidity and Capital Resources -- Electric Transmission and Energy Markets.

We estimate that our operating revenues for the second quarter of 2009 were \$7.3 million higher when compared to the same period in 2008 because of warmer weather, as measured in cooling degree days. While the second quarter of 2009 was 19.8% cooler than normal, it was 22.9% warmer than the same period in 2008.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by \$44.9 million, or 15.0%, when compared to the second quarter of 2008. This decline was caused by lower MWh sales and lower natural gas and purchased power prices, partially offset by higher coal and related transportation costs.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the second quarter of 2009 with the second quarter of 2008. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues decreased by \$38.5 million, or 34.7%, primarily due to lower natural gas prices.

	Three Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	\$72.3	(\$38.5)	\$110.8
Cost of Gas Sold	42.3	37.9	80.2
Gross Margin	<u>\$30.0</u>	<u>(\$0.6)</u>	<u>\$30.6</u>

PART I -- FINANCIAL INFORMATION -- (Cont'd)

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2009 with the second quarter of 2008:

Gas Utility Operations	Three Months Ended June 30					
	Gross Margin			Therm Deliveries		
	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$21.1	\$1.1	\$20.0	48.5	4.8	43.7
Commercial/Industrial	5.6	(0.6)	6.2	28.0	(0.4)	28.4
Interruptible	0.1	-	0.1	1.1	(0.4)	1.5
Total Retail	26.8	0.5	26.3	77.6	4.0	73.6
Transported Gas	2.5	(1.0)	3.5	67.8	5.5	62.3
Other	0.7	(0.1)	0.8	-	-	-
Total	\$30.0	(\$0.6)	\$30.6	145.4	9.5	135.9
Weather -- Degree Days (a)						
Heating (954 Normal)				946	(16)	962

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

Our gas margin decreased by \$0.6 million, or approximately 2.0%, when compared to the second quarter of 2008. During the second quarter of 2009, we experienced slightly warmer weather than in the same period during 2008. As measured by heating degree days, the second quarter of 2009 was 1.7% warmer than the same period in 2008 and 0.8% warmer than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by \$11.0 million, or approximately 3.5%, when compared to the second quarter of 2008. This decrease is primarily related to reduced operating expenses at our power plants and electric distribution system as a result of lower MWh sales.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by \$2.7 million, or approximately 4.3%, when compared to the second quarter of 2008. This increase was the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed into service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements with our regulators to allow for the net gain on the sale of approximately \$902.2 million 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 the second quarter of 2009 and 2008, we issued approximately \$55.1 million and \$87.0 million of bill credits, respectively.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Other Income, net**

Other income, net increased by approximately \$1.7 million, or 36.2%, when compared to the second quarter of 2008. This increase primarily relates to increased AFUDC - Equity due to the construction of our Oak Creek AQCS project.

Interest Expense, net

Interest Expense, net	Three Months Ended June 30	
	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	\$26.7	\$20.1
Less: Capitalized Interest	1.5	0.7
Interest Expense, net	\$25.2	\$19.4

Our gross interest costs increased by \$6.6 million, or 32.8%, when compared to the second quarter of 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 \$0.8 million due to increased capital expenditures related to our Oak Creek AQCS project. As a result, our net interest expense increased by \$5.8 million, or 29.9%, as compared to the second quarter of 2008.

Income Taxes

For the second quarter of 2009, our effective tax rate was 36.5% compared to 37.0% for the second quarter of 2008. For additional information, see Note F -- Income Taxes in our 2008 Annual Report on Form 10-K.

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2009**EARNINGS**

We had net income of \$150.3 million for the first six months of 2009, an increase of \$14.2 million, or 10.4%, from the first six months of 2008. A more detailed analysis of our financial results follows.

Our operating income was \$245.3 million for the first six months of 2009, an increase of \$17.4 million, or 7.6%, from the first six months of 2008. The increase in operating income was primarily caused by favorable recoveries of revenues associated with fuel and purchased power. During the first six months of 2009, we experienced favorable fuel recoveries of approximately \$24 million. During the same period in 2008, we experienced unfavorable fuel recoveries of approximately \$20 million. While we experienced a net \$44 million positive increase in fuel recoveries in the first six months of 2009 as compared to the same period in 2008, we expect a substantial portion of the favorable fuel recoveries to reverse by the end of the year as a result of the PSCW's approval of the request we filed to reduce Wisconsin retail electric rates for calendar year 2009. For additional information on the rate filing, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Electric Utility Revenues and Sales**

The following table compares electric utility operating revenues and MWh sales by customer class during the first six months of 2009 with the first six months of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

Electric Utility Operations	Six Months Ended June 30					
	Electric Revenues			MWh Sales		
	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$485.4	\$25.4	\$460.0	3,914.9	(75.4)	3,990.3
Small Commercial/Industrial	431.7	10.5	421.2	4,272.1	(168.8)	4,440.9
Large Commercial/Industrial	285.6	(37.4)	323.0	4,343.3	(1,097.0)	5,440.3
Other - Retail	10.5	0.2	10.3	77.4	(2.6)	80.0
Total Retail	1,213.2	(1.3)	1,214.5	12,607.7	(1,343.8)	13,951.5
Wholesale - Other	62.0	(12.1)	74.1	881.8	(500.4)	1,382.2
Resale - Utilities	23.8	9.4	14.4	691.6	378.2	313.4
Other Operating	30.9	10.3	20.6	-	-	-
Total	\$1,329.9	\$6.3	\$1,323.6	14,181.1	(1,466.0)	15,647.1

Weather -- Degree Days (a)

Heating (4,194 Normal)	4,404	(111)	4,515
Cooling (168 Normal)	134	25	109

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

Our electric utility operating revenues increased by \$6.3 million, or 0.5%, when compared to the first six months of 2008. We estimate that revenues were \$47.2 million higher due to pricing increases that we received during January 2008 as part of the 2008 PSCW rate case that were in effect for all six months in 2009, as well as net pricing increases we received from the PSCW related to fuel. We also estimate that our electric revenues increased by \$41.7 million as a result of fewer bill credits to our customers from the sale of Point Beach during the first six months of 2009 as compared to the same period in 2008. For more information on bill credits, see Amortization of Gain in Results of Operations -- Six Months Ended June 30, 2009.

We estimate that warmer weather during the first half of 2009 as compared to the first half of 2008 increased operating revenues by approximately \$5.1 million. As measured by cooling degree days, the first six months of 2009 were approximately 22.9% warmer as compared to the first six months of 2008.

Our total electric sales volumes decreased by approximately 9.4% as compared to the first six months of 2008, with retail sales volumes declining approximately 9.6%. Approximately 9.1% of the decline in retail sales volumes relates to sales to our small and large commercial and industrial customers. The primary reason for the reduced sales volumes relates to a decline in economic conditions during the first six months of 2009 as compared to the same period in 2008.

For a discussion of anticipated impacts of the downturn in the economy and the April 2009 fuel cost decrease filing for the remainder of 2009, see Results of Operations -- Three Months Ended June 30, 2009.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Fuel and Purchased Power**

Our fuel and purchased power costs decreased by \$117.1 million, or 18.4%, when compared to the first six months of 2008. The largest factor related to this decrease was a \$41.2 million one-time amortization of deferred fuel costs pursuant to the January 2008 PSCW rate order. Adjusted for the one-time amortization, our fuel and purchased power costs decreased by \$75.9 million, or 11.9%. This decline was caused by lower MWh sales and lower natural gas and purchased power prices, partially offset by higher coal and related transportation costs.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first six months of 2009 with the first six months of 2008. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues decreased by \$61.2 million, or 14.5%, primarily due to lower natural gas prices and milder weather.

	Six Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	\$359.8	(\$61.2)	\$421.0
Cost of Gas Sold	259.5	57.8	317.3
Gross Margin	<u>\$100.3</u>	<u>(\$3.4)</u>	<u>\$103.7</u>

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2009 with the first six months of 2008:

Gas Utility Operations	Six Months Ended June 30					
	Gross Margin			Therm Deliveries		
	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$67.8	(\$0.7)	\$68.5	218.4	(3.6)	222.0
Commercial/Industrial	23.7	(1.2)	24.9	128.1	(4.5)	132.6
Interruptible	0.3	(0.1)	0.4	3.6	(0.6)	4.2
Total Retail	<u>91.8</u>	<u>(2.0)</u>	<u>93.8</u>	<u>350.1</u>	<u>(8.7)</u>	<u>358.8</u>
Transported Gas	7.0	(1.4)	8.4	159.4	(5.1)	164.5
Other	1.5	-	1.5	-	-	-
Total	<u>\$100.3</u>	<u>(\$3.4)</u>	<u>\$103.7</u>	<u>509.5</u>	<u>(13.8)</u>	<u>523.3</u>
Weather -- Degree Days (a)						
Heating (4,194 Normal)				4,404	(111)	4,515

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

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Our gas margin decreased by \$3.4 million, or 3.3%, when compared to the first six months of 2008. We estimate that approximately \$2.7 million of this decrease relates to a decline in sales volumes as a result of milder weather and a decline in economic conditions during the first six months of 2009 as compared to the same period in 2008. As measured by heating degree days, the first six months of 2009 were 2.5% warmer than the same period in 2008 and 5.0% cooler than normal. Pricing increases that we received during January 2008 as part of the January 2008 PSCW rate case that were in effect for all six months in 2009 partially offset the negative drivers.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by \$33.0 million, or approximately 5.0%, when compared to the first six months of 2008. The largest factor for this decrease relates to a \$43.8 million one-time amortization of deferred bad debt costs in connection with the January 2008 PSCW rate order, which we recorded in January 2008. The January 2008 PSCW rate order, which was in effect for all six months in 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 the first six months of 2009 as compared to the same period in 2008.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by \$6.8 million, or approximately 5.4%, when compared to the first six months of 2008. This increase was primarily the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed into service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements with our regulators to allow for the net gain on the sale of approximately \$902.2 million 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.

The following table compares the amortization of the gain during the six months ended June 30:

Amortization of Gain	2009	2008
	(Millions of Dollars)	
Bill Credits - Retail	\$119.3	\$161.0
One-Time Amortization	-	85.0
Total Amortization of Gain	\$119.3	\$246.0

For the remainder of 2009, we expect to see a reduction in the Amortization of Gain as compared to 2008 because of the one-time entry identified above and a one-time \$62.5 million FERC approved refund to our wholesale customers in the third quarter of 2008, as well as an expected approximately \$108 million annual decrease in bill credits to retail customers.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Other Income, net**

Other income, net decreased by approximately \$1.1 million, or 8.2%, when compared to the first six months of 2008. This decrease primarily relates to reduced property sales during the first six months of 2009 as compared to the same period in 2008.

Interest Expense, net

Interest Expense, net	Six Months Ended June 30	
	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	\$53.5	\$44.0
Less: Capitalized Interest	2.7	1.8
Interest Expense, net	<u>\$50.8</u>	<u>\$42.2</u>

Our gross interest costs increased by \$9.5 million, or 21.6%, when compared to the six months ended June 30, 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 \$0.9 million due to increased capital expenditures related to our Oak Creek AQCS project. As a result, our net interest expense increased by \$8.6 million, or 20.4%, as compared to the first six months of 2008.

Income Taxes

For the first six months of 2009, our effective tax rate was 35.2% compared to 38.1% for the first six months of 2008. For additional information, see Note F -- Income Taxes in our 2008 Annual Report on Form 10-K.

LIQUIDITY AND CAPITAL RESOURCES**CASH FLOWS**

The following summarizes our cash flows during the first six months of 2009 and 2008:

	Six Months Ended June 30	
	2009	2008
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	\$11.5	\$320.6
Investing Activities	(\$163.0)	(\$121.8)
Financing Activities	\$133.3	(\$205.7)

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Operating Activities**

Cash provided by operating activities was \$11.5 million during the six months ended June 30, 2009, which was \$309.1 million lower than the same period in 2008. Although we experienced an increase in net income and depreciation during the first six months of 2009, there were two large factors that reduced operating cash flows. During the first six months of 2009, we contributed \$283.8 million to Wisconsin Energy's benefit plans compared to \$37.9 million during the first six months of 2008. The second factor related to an increase in cash used for working capital related to our coal and natural gas inventories.

Investing Activities

Cash used in investing activities was \$163.0 million during the six months ended June 30, 2009, which was \$41.2 million higher than the same period in 2008. The increase primarily reflects a reduction in the release of restricted cash and an increased investment in our transmission affiliate. This increase was partially offset by lower capital expenditures during the first six months of 2009.

During the first six months of 2009, we released \$51.0 million less from restricted cash as compared to the same period in 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.

During the first six months of 2009, our capital expenditures decreased by \$20.0 million as compared to the same period in 2008 primarily due to the completion of our Blue Sky Green Field wind project in 2008.

Financing Activities

Cash provided by financing activities was \$133.3 million during the six months ended June 30, 2009 compared to \$205.7 million used in financing activities during the same period in 2008. During the first six months of 2009, we increased our debt levels by approximately \$223.2 million compared to a \$97.4 million reduction in our debt levels during the same period in 2008.

CAPITAL RESOURCES AND REQUIREMENTS**Capital Resources**

We anticipate meeting our capital requirements during the remaining six months of 2009 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 2009, 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.

Despite the continued turmoil in the global credit markets, we still currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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 June 30, 2009, we had approximately \$471.9 million of available, undrawn lines under our bank back-up credit facility. As of June 30, 2009, we had approximately \$223.5 million of short-term debt 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 June 30, 2009:

<u>Total Facility *</u>	<u>Letters of Credit</u>	<u>Credit Available *</u>	<u>Facility Expiration</u>
(Millions of Dollars)			
\$476.4	\$4.5	\$471.9	March 2011

* Excludes Lehman's commitment

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 June 30, 2009:

	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
Commercial Paper	A-2	P-1	F1
Senior Secured 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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Capital Requirements**

Capital requirements during the remainder of 2009 are expected to be principally for capital expenditures related to our electric distribution system and environmental controls at our existing Oak Creek generating units. Our 2009 annual capital expenditure budget is approximately \$600 million.

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 continue to 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 further information, see Note 7 -- Guarantees and Note 9 -- Variable Interest Entities in the Notes to Consolidated Condensed Financial Statements in this report.

Contractual Obligations/Commercial Commitments: Our total contractual obligations and other commercial commitments were approximately \$22.3 billion as of June 30, 2009 compared with \$21.9 billion as of December 31, 2008. Our total contractual obligations and other commercial commitments as of June 30, 2009 increased compared with December 31, 2008 primarily due to increased capital lease obligations related to the Oak Creek water intake system that was placed into service in January 2009.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

The following is a discussion of certain factors that may affect our results of operations, liquidity and capital resources. The following discussion should be read together with the information under the heading "Factors Affecting Results, Liquidity and Capital Resources" in Item 7 of our 2008 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, Wisconsin Energy's PTF strategy, rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

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 from We Power under long-term leases, and we expect to recover the lease payments in our electric rates. The Oak Creek expansion is currently being constructed by We Power, and we expect to recover future lease payments in our electric rates. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2008 Annual Report on Form 10-K for additional information on PTF.

Oak Creek Expansion

Construction Status: In July 2008, Bechtel, the contractor of the Oak Creek expansion under a fixed price contract, notified We Power in a letter that it forecasts the in-service date of unit 1 to be delayed three months beyond the guaranteed contract date of September 29, 2009. Bechtel also advised We Power in the letter that it forecasts the in-service date of unit 2 to be one month earlier than the guaranteed contract date of September 29, 2010.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

We Power received Bechtel's claims for schedule and cost relief on December 22, 2008. Although Bechtel did not change the forecasted in-service dates, it did request schedule relief that would result in six months of relief from liquidated damages beyond the guaranteed contract date for unit 1 and three months of relief from liquidated damages beyond the guaranteed contract date for unit 2. Bechtel's claims are based on the alleged effects of severe winter 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 FNTP in 2005.

Based on Bechtel's July 2008 communication, We Power notified Bechtel on September 29, 2008 that it was invoking the formal dispute resolution process provided in the contract in order to resolve certain issues related to the rights of the parties under the contract. We Power subsequently agreed with Bechtel to combine these issues and Bechtel's claim into one mediation. Mediation was unsuccessful and, therefore, as required by the contract, the parties submitted the claims to binding arbitration, which We Power anticipates will be concluded in 2010.

Bechtel continues to target an in-service date for unit 1 three months beyond the guaranteed contract date of September 29, 2009, and an in-service date for unit 2 one month earlier than the guaranteed contract date of September 29, 2010. Bechtel fell behind this revised target schedule in moving from construction to start-up, but developed a recovery plan and added resources in an effort to recover lost time. Bechtel has made, and continues to make, significant construction and start-up progress; however, at this time it has not fully kept pace with its revised schedule.

RATES AND REGULATORY MATTERS

2010 Rate Case: On March 13, 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 have 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. We have requested that these rates become effective January 1, 2010.

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 results in us increasing our request from \$76.5 million to \$126.0 million. However, those same lower sales also made available \$24.0 million in added bill credits from the sale of Point Beach, resulting in a net increase to customers of 3.9%.

As part of our electric rate proceeding, we have asked the PSCW to make the following determinations:

- New proposed depreciation rates will become effective prior to or concurrent with the implementation of the new base rates requested in the proceeding.
- Certain regulatory assets currently scheduled to be fully amortized over the next four years will instead be amortized over the next eight years.
- We will continue to receive 100% AFUDC for capital expenditures on environmental control projects at our Oak Creek power plant, as well as 100% AFUDC for capital expenditures on an environmental control project at Edgewater 5 and on renewable energy projects including the proposed Glacier Hills Wind Park.
- If recommendations of the Wisconsin Governor's Task Force on Global Warming are enacted, we will have the option of applying for a limited reopener or for deferral accounting to address any increased costs or reduced sales that result from such enactment.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

2010 Michigan Price Increase Request: In July 2009, we filed a \$42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. This rate increase is expected to be implemented in three phases throughout 2010. We expect the first phase to be effective in early 2010. A final decision from the MPSC is expected in July 2010. Pursuant to recently enacted Michigan legislation, we may, upon the satisfaction of certain conditions, self-implement a rate increase request, subject to refund with interest.

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, 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 Pricing: During 2007, we initiated rate proceedings. We asked the PSCW to approve a comprehensive plan which would result in price increases of \$648.6 million for our electric customers in Wisconsin. This price increase would be reduced by expected bill credits resulting from the sale of Point Beach. The initial rate filing estimated bill credits of \$371.0 million in 2008 and \$187.5 million in 2009, resulting in net pricing increases of 7.5% in 2008 and 7.5% in 2009. In addition, we requested a 1.8% price increase in 2008 for our gas customers and an approximately 16.0% price increase in 2008 for all steam customers in Milwaukee.

Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with the new PTF plants; recovery of costs associated with transmission; compliance with environmental regulations; continuation of investment in renewable and efficiency programs, including the Blue Sky Green Field wind project; and scheduled recovery of regulatory assets.

On January 17, 2008, the PSCW approved pricing increases for us as follows:

- \$389.1 million (17.2%) in electric rates - the pricing increase will be offset by \$315.9 million in bill credits in 2008 and \$240.7 million in bill credits in 2009, resulting in a net increase of \$73.2 million (3.2%) and \$75.2 million (3.2%), respectively;
- \$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.

We expect to provide a total of approximately \$710.0 million of bill credits to our Wisconsin customers over the three year period ending December 31, 2010. As of June 30, 2009, we have issued approximately \$404.5 million of bill credits to Wisconsin retail customers.

2008 Michigan Price Increase: In January 2008, we filed a rate increase request with the MPSC. This request represents an increase in electric rates of 14.7%, or \$22.0 million, to support the growing demand for electricity, 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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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 and \$10.0 million of RSG credits we hoped to receive from MISO. The refund was issued during the second quarter of 2009.

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 originally estimated the cost of this project to be \$750 million (\$830 million including AFUDC). We now expect the cost of completing this project to be approximately \$800 million (\$960 million including AFUDC). The cost increase is primarily attributable to increases in material prices that occurred prior to the commencement of construction and material procurement activities in July 2008. The increase in AFUDC is based on our updated calculation that assumes AFUDC will accrue on 100% of the construction cost until the facilities are placed in service, which is consistent with the 2010 rate case filing. The cost of constructing these facilities is included in our estimates of the costs to implement the Consent Decree with the EPA.

Depreciation Rates: Periodically, we engage consultants to perform depreciation studies on our utility assets to make recommendations regarding our depreciation rates. In 2008, a consultant completed a depreciation study that concluded that we should reduce our utility depreciation rates because of longer asset lives and increased salvage values. The consultant estimated that the new proposed rates would reduce annual depreciation expense by approximately \$41 million. In January 2009, we filed the depreciation study with the PSCW. If the PSCW approves the depreciation study, we would expect to implement the new depreciation rates in late 2009 or early 2010. We do not expect the new depreciation rates to have a material impact on earnings because we anticipate that the new depreciation rates will be considered when the PSCW sets our 2010 electric and gas prices.

See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding our rates and other regulatory matters.

WIND GENERATION

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. We currently expect to install 90 wind turbines with generating capacity of up to approximately 207 MW, subject to the final site configuration. We expect 2012 to be the first full year of operation, subject to regulatory approvals.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**ELECTRIC TRANSMISSION AND ENERGY MARKETS**

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 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 that the current transmission cost allocation methodology is just and reasonable and should continue in the future. These orders are subject to appeals.

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.

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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Additionally, new arguments have been filed with FERC in relation to the Ancillary Services Market tariff language regarding the RSG cost allocation. In response, MISO has once again filed a new rate proposal related to the RSG cost allocation methodology that, if approved, is expected to be implemented in late 2009 or early 2010.

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 ARR 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.

LEGAL MATTERS

Cash Balance Pension Plan: On June 30, 2009, a lawsuit by a retiree plaintiff was filed against the Plan. Counsel representing the plaintiff is attempting to seek certification for a class of plaintiffs including the plaintiff and 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.

ENVIRONMENTAL MATTERS

National Ambient Air Quality Standards: In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and PM_{2.5}. In December 2006, the EPA further revised the PM_{2.5} standard, and in March 2008, the EPA announced its decision to further lower the 8-hour ozone standard.

8-hour Ozone Standard: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 8-hour ozone NAAQS. 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 NAAQS. Instead of submitting a SIP, Wisconsin submitted a request to redesignate all counties in southeastern Wisconsin to be 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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

In March 2008, the EPA announced its decision to further lower the 8-hour ozone standard. Although 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.

PM_{2.5} Standard: In December 2004, the EPA designated PM_{2.5} non-attainment areas in the country. 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. Until such time as the EPA revises the 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 the 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 and PWGS.

Clean Air Mercury Rule: The EPA issued the final CAMR in March 2005, following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR would limit mercury emissions from new and existing coal-fired power plants and cap utility mercury emissions in two phases, applicable in 2010 and 2018. The caps would limit emissions at approximately 20% and ultimately 70% below current utility mercury levels.

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 re-consideration. The D.C. Circuit denied a request for a rehearing and the parties subsequently petitioned the U.S. Supreme Court for review of the D.C. Circuit's decision. In February 2009, the U.S. Supreme Court denied the petition for certiorari. In December 2008, a number of environmental groups also filed a complaint with the D.C. Circuit asking that the court place the EPA on a schedule for promulgating Maximum Achievable Control Technology limits for electric utilities. This latest complaint is still being processed by the D.C. Circuit.

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 EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States are then required to determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO₂ and ammonia. States were required to submit SIPs to implement CAVR to the EPA by December 2007. Wisconsin has not yet submitted a SIP. Michigan submitted a SIP, which was partially approved. The reductions associated with the state plans are scheduled to begin to take effect in 2014, with full implementation before 2018. 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. Failure to submit an approved SIP does not initiate any federal sanctions against the states.

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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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.

Clean Water Act: Section 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. This law dates back to 1972; however, prior to September 2004, there were no federal rules that defined precisely how states and the EPA regions were to make BTA determinations for existing facilities. In September 2004, the EPA adopted its "Phase II rule" which established, for the first time, national performance standards and compliance alternatives for existing facilities that are designed to minimize the potential adverse environmental 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 issued a decision concerning the Phase II rule for existing facilities (*Riverkeeper, Inc. v. EPA*, 475 F. 3d 83 (2d Cir. 2007)). The Second Circuit found certain portions of the rule impermissible, including portions that permitted approval of water intake system technologies based on a cost-benefit analysis, and remanded several parts of the Phase II rule to the EPA for further consideration or potential additional rulemaking. Subsequently, industry representatives sought the U.S. Supreme Court's review of the Second Circuit decision.

In April 2009, the Supreme Court issued its decision on the Phase II rule. As it relates to the cost-benefit analysis, the Supreme Court reversed the Second Circuit 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 did not address other aspects of the Second Circuit decision. 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.

Climate Change Legislation: Global warming is increasingly a concern for the energy industry. Federal and state legislative 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. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

The American Clean Energy and Security Act of 2009 (otherwise known as the Waxman-Markey Bill) passed the U.S. House of Representatives on June 26, 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. The debate regarding federal climate legislation is ongoing in the U.S. Senate, which is considering similar legislation.

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. The stated goal of the platform is to "maximize the energy resources and economic advantages and opportunities of Midwestern states while reducing emissions of atmospheric CO₂ and other greenhouse gases". The group charged with developing a regional cap-and-trade system

PART I -- FINANCIAL INFORMATION -- (Cont'd)

under this Accord has recommended a plan that calls for a 20% reduction in greenhouse gas emissions from 2005 levels by 2020 and an 80% reduction by 2050. The group has stated that it prefers a federal cap-and-trade system, but it developed the plan in the event Congress fails to act by 2012.

We continue to monitor the legislative and regulatory developments in this area, including those in the U.S. Congress.

Depending on the extent of rate recovery, we anticipate that any cap-and-trade program that may be adopted, either at the federal or regional level, could have a material adverse impact on our electric generation and natural gas distribution operations. Such regulation could make some of our electric generating units uneconomic to maintain or operate, and could affect future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with any future legislation and/or regulation that requires a reduction in greenhouse gas emissions or that cost recovery will not be delayed or otherwise conditioned. Although we expect the regulation of greenhouse gas emissions could have a material adverse impact on our operations and rates, we believe it is premature to attempt to quantify the possible costs of the impacts.

EPA Advance Notice of Proposed Rulemaking: In July 2008, the EPA issued an ANPR seeking comment on a large array of possible regulatory actions it is contemplating under the CAA to reduce greenhouse gas emissions. The proposed rules impact virtually all aspects of the economy including electric and natural gas utilities.

The EPA ANPR followed a U.S. Supreme Court decision in 2007 requiring the EPA to regulate greenhouse gas emissions from new motor vehicles under the CAA if it finds that they endanger public health or welfare. The ANPR sought comment on whether the EPA should make that finding and, if so, the types of regulations it should adopt. The comment period has closed, and in April 2009 the EPA issued for public comment its finding that greenhouse gas emissions endanger public health and welfare, and that new motor vehicles contribute to greenhouse gas emissions and the threat of climate change. The EPA states that the proposed action, if finalized, would not itself impose any requirements on industry or other entities. An endangerment finding is the first step in the process of regulating greenhouse gas emissions under the CAA.

A decision to regulate greenhouse gas emissions under one section of the CAA could lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants like electric generating plants. Although it is difficult to predict at this time, such a finding or subsequent rulemaking could have a material adverse impact on our operations.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For information concerning market risk exposures at Wisconsin Electric Power Company, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 2008 Annual Report on Form 10-K.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**ITEM 4T. 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.

Internal Control Over Financial Reporting: There has not been any change in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter to which this report relates that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II -- OTHER INFORMATION**ITEM 1. LEGAL PROCEEDINGS**

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2008 Annual Report on Form 10-K.

In addition to those legal proceedings discussed in our reports to the SEC, 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 legal proceedings cannot be predicted with certainty, we believe, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material adverse effect on our financial statements.

RATES AND REGULATORY MATTERS

See Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where we do business.

OTHER MATTERS

Cash Balance Pension Plan: See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part I of this report for information concerning an alleged violation of ERISA by Wisconsin Energy's cash balance pension plan.

PART II -- OTHER INFORMATION -- (Cont'd)**ITEM 1A. RISK FACTORS**

See Item 1A. Risk Factors in our 2008 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

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

At our 2009 Annual Meeting of Stockholders held on May 1, 2009, for which we did not solicit proxies, the nine incumbent directors listed in our Information Statement dated April 6, 2009 (Information Statement) were elected for terms expiring in 2010. Each director received 33,289,327 votes (100% of votes cast). Directors are elected by a plurality of the votes cast by the shares entitled to vote. Any shares not voted, whether by withheld authority or otherwise, have no effect in the election of directors. There was no solicitation in opposition to the nominees in the Information Statement.

Further information concerning this matter is contained in our Information Statement.

ITEM 6. EXHIBITSExhibit No.**10 Material Contracts**

- 10.1 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 06/30/2009 Form 10-Q.)

12 Statements re Computation of Ratios

- 12.1 Statement of Computation of Ratio of Earnings to Fixed Charges

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.

SIGNATURES

Pursuant to the requirements 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
(Registrant)

Date: August 4, 2009

/s/STEPHEN P. DICKSON
Stephen P. Dickson, Vice President and Controller, Principal
Accounting Officer and duly authorized officer