WISCONSIN ENERGY CORP
Form 10-Q
October 30, 2009

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

September 30, 2009

Commission File Number	Registrant; State of Incorporation Address; and Telephone Number	IRS Employer Identification No.
001-09057	WISCONSIN ENERGY CORPORATION (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (&sect 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[X] 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 [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

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

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

Common Stock, $.01 Par Value, 116,911,016 shares outstanding.

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2009

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Part II -- Other Information

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 Energy Subsidiaries and Affiliates

Primary Subsidiaries	
Edison Sault	Edison Sault Electric Company
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2

PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2

Other Affiliates

ATC	American Transmission Company LLC
ERS	Elm Road Services, LLC
Wispark	Wispark LLC

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
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
CPCN	Certificate of Public Convenience and Necessity

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:

Energy Policy Act	Energy Policy Act of 2005
ERISA	Employee Retirement Income Security Act of 1974
Fitch	Fitch Ratings
FNTP	Full Notice To Proceed
FTRs	Financial Transmission Rights
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Markets
Moody's	Moody's Investor Service
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
PSEG	Public Service Enterprise Group
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services

Measurements

Dth	Dekatherm(s) (One Dth equals one million British Thermal Units)
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
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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 our 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.
- Factors which impede or delay execution of our 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, including PSCW approval of projects and costs contained in the agreement.
- 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.
- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.
- 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 any of our subsidiaries; and our credit ratings.
- The investment performance of our 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.
- The cyclical nature of property values that could affect our real estate investments.
- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.
- 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 Energy Corporation 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 Energy Corporation is a diversified holding company which conducts its operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our primary subsidiaries are Wisconsin Electric, Wisconsin Gas and We Power.

Utility Energy Segment:

Our utility energy segment consists of: Wisconsin Electric, which serves electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metropolitan Milwaukee, Wisconsin; Wisconsin Gas, which serves gas customers in Wisconsin; and Edison Sault, which serves electric customers in the Upper Peninsula of Michigan. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies".

Non-Utility Energy Segment:

Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2008 Annual Report on Form 10-K for more information on PTF.

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 ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$821.9	$851.5	$3,060.6	$3,228.0
Operating Expenses				
Fuel and purchased power	292.6	344.1	812.6	980.4
Cost of gas sold	63.2	95.7	667.9	841.4
Other operation and maintenance	303.8	320.0	946.5	1,022.7
Depreciation, decommissioning and amortization	87.3	84.0	259.4	242.1
Property and revenue taxes	28.0	26.7	84.3	81.0
Total Operating Expenses	774.9	870.5	2,770.7	3,167.6
Amortization of Gain	57.9	157.4	177.2	403.4
Operating Income	104.9	138.4	467.1	463.8
Equity in Earnings of Transmission Affiliate	14.9	14.4	43.6	38.0
Other Income, net	10.4	7.1	24.0	25.6
Interest Expense, net	38.4	38.8	119.0	113.4
Income from Continuing Operations Before Income Taxes	91.8	121.1	415.7	414.0
Income Taxes	33.1	44.5	152.1	156.2
Income from Continuing Operations	58.7	76.6	263.6	257.8
Income (Loss) from Discontinued Operations, Net of Tax	(0.2)	0.9	0.1	0.9
Net Income	$58.5	$77.5	$263.7	$258.7
Earnings Per Share (Basic)				
Continuing operations	$0.50	$0.65	$2.26	$2.20
Discontinued operations	-	0.01	-	0.01
Total Earnings Per Share (Basic)	$0.50	$0.66	$2.26	$2.21
Earnings Per Share (Diluted)				

Continuing operations	$0.50	$0.64	$2.24	$2.18
Discontinued operations	-	0.01	-	0.01
Total Earnings Per Share (Diluted)	$0.50	$0.65	$2.24	$2.19
Weighted Average Common Shares Outstanding (Millions)				
Basic	116.9	116.9	116.9	116.9
Diluted	118.0	118.2	117.9	118.2
Dividends Per Share of Common Stock	$0.3375	$0.27	$1.0125	$0.81

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited) September 30, 2009	December 31, 2008
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$ 10,235.2	$ 9,909.4
Accumulated depreciation	(3,465.6)	(3,312.9)
	6,769.6	6,596.5
Construction work in progress	2,062.1	1,829.9
Leased facilities, net	72.0	76.2
Net Property, Plant and Equipment	8,903.7	8,502.6
Investments		
Restricted cash	56.5	172.4
Equity investment in transmission affiliate	303.3	276.3
Other	37.7	41.6
Total Investments	397.5	490.3

Current Assets		
Cash and cash equivalents	10.7	32.5
Restricted cash	180.5	214.1
Accounts receivable	309.5	369.5
Accrued revenues	147.8	341.2
Materials, supplies and inventories	388.9	344.7
Regulatory assets	69.6	82.5
Prepayments and other	221.6	323.0
Total Current Assets	1,328.6	1,707.5
Deferred Charges and Other Assets		
Regulatory assets	1,186.3	1,261.1
Goodwill	441.9	441.9
Other	162.7	214.4
Total Deferred Charges and Other Assets	1,790.9	1,917.4
Total Assets	$ 12,420.7	$ 12,617.8
Capitalization and Liabilities		
Capitalization		
Common equity	$ 3,486.9	$ 3,336.9
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,631.2	4,074.7
Total Capitalization	7,148.5	7,442.0
Current Liabilities		
Long-term debt due currently	312.5	61.8
Short-term debt	938.0	602.3
Accounts payable	263.8	441.0
Regulatory liabilities	234.4	310.8
Other	261.2	319.2
Total Current Liabilities	2,009.9	1,735.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	949.2	1,084.4
Deferred income taxes - long-term	950.0	814.0
Deferred revenue, net	687.9	545.4
Pension and other benefit obligations	316.9	635.0
Other	358.3	361.9
Total Deferred Credits and Other Liabilities	3,262.3	3,440.7
Total Capitalization and Liabilities	$ 12,420.7	$ 12,617.8

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS

(Unaudited)

		Nine Months Ended September 30	
		2009	2008
		(Millions of Dollars)	
Operating Activities			
Net income		$ 263.7	$ 258.7
Reconciliation to cash			
Depreciation, decommissioning and amortization		264.3	249.9
Amortization of gain		(177.2)	(403.4)
Equity in earnings of transmission affiliate		(43.6)	(38.0)
Distributions from transmission affiliate		34.5	27.8
Deferred income taxes and investment tax credits, net		121.9	155.4
Deferred revenue		148.4	151.1
Contributions to benefit plans		(289.3)	(48.4)
Change in -	Accounts receivable and accrued revenues	238.1	208.3
	Inventories	(44.2)	1.8
	Other current assets	61.8	4.1
	Accounts payable	(188.8)	(70.7)
	Accrued income taxes, net	22.2	(7.0)
	Deferred costs, net	34.6	69.9
	Other current liabilities	11.7	22.9
Other, net		(21.6)	60.6
Cash Provided by Operating Activities		436.5	643.0
Investing Activities			

Capital expenditures	(555.8)	(888.9)
Investment in transmission affiliate	(18.1)	(17.4)
Proceeds from asset sales, net	15.7	13.8
Change in restricted cash	149.5	280.7
Other, net	(69.9)	(69.9)
Cash Used in Investing Activities	(478.6)	(681.7)
Financing Activities		
Exercise of stock options	12.5	10.0
Purchase of common stock	(21.0)	(19.9)
Dividends paid on common stock	(118.4)	(94.7)
Issuance of long-term debt	11.5	303.0
Retirement and repurchase of long-term debt	(202.0)	(176.2)
Change in short-term debt	335.7	13.5
Other, net	2.0	(1.1)
Cash Provided by Financing Activities	20.3	34.6
Change in Cash and Cash Equivalents	(21.8)	(4.1)
Cash and Cash Equivalents at Beginning of Period	32.5	27.4
Cash and Cash Equivalents at End of Period	$ 10.7	$ 23.3

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

WISCONSIN ENERGY CORPORATION
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 for 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 nine months ended September 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.

Reclassifications:

We have reclassified certain prior year financial statement amounts to conform to their current year presentation. These reclassifications had no effect on total assets, net income or earnings per share.

The reclassifications relate to the reporting of discontinued operations. The footnotes contained herein reflect continuing operations for all periods presented. For further information, see Note 6.

Subsequent Events:

We have evaluated and determined that no material events took place after our balance sheet date of September 30, 2009 through our financial statement issuance date of October 30, 2009, except as discussed in Note 15.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements:

In September 2006, the FASB issued new accounting guidance relating to fair value measurements and also issued updated accounting guidance in 2008 and 2009. This guidance defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value, expands disclosures related to fair value measurements and was effective for financial statements issued for fiscal years beginning after November 15, 2007. This adoption did not have a significant financial impact on our financial condition, results of operations or cash flow. See Note 7 -- Fair Value Measurements for required disclosures.

Noncontrolling Interests in Consolidated Financial Statements:

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

Disclosures about Derivative Instruments and Hedging Activities:

In March 2008, the FASB issued new accounting guidance relating to derivative instruments and hedging activities. This guidance requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements, and was effective for fiscal years beginning after November 15, 2008. We adopted these provisions effective January 1, 2009. This adoption did not have any financial impact on our financial condition, results of operations or cash flows. See Note 8 -- Derivative Instruments for required disclosures.

Subsequent Events:

In May 2009, the FASB issued new accounting guidance relating to management's assessment of subsequent events. This guidance clarifies that management must evaluate, as of each reporting period, events or transactions that occur after the balance sheet date through the date the financial statements are issued or are available to be issued, and was effective for interim and annual periods ending after June 15, 2009. We adopted these provisions effective June 30, 2009. This adoption had no 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 new accounting guidance, 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 these provisions effective June 30, 2009. This adoption had no financial impact on our financial condition, results of operations or cash flows. See Note 7 -- Fair Value Measurements for required disclosures.

Recognition and Presentation of Other-Than-Temporary Impairments:

In April 2009, the FASB issued new accounting guidance that amended the other-than-temporary impairment guidance for debt securities to be more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in financial statements. We adopted these provisions effective June 30, 2009. This adoption had no 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 new accounting guidance related to variable interest entity consolidation. The purpose of this guidance is to improve financial reporting by enterprises with variable interest entities. The new guidance is effective for all new and existing variable interest entities for fiscal years beginning after November 15, 2009. We expect to adopt these provisions on January 1, 2010.

Employers' Disclosures about Post-retirement Benefit Plan Assets

: In December 2008, the FASB issued new accounting guidance for employer's disclosures about plan assets of a defined benefit pension or other post-retirement plans. This new guidance 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 these provisions on December 31, 2009.

3 -- ACCOUNTING AND REPORTING fOR POWER THE FUTURE GENERATING UNITS

Background:

As part of our PTF strategy, our non-utility subsidiary, We Power, is building four new generating units (PWGS 1 and 2 and OC 1 and 2) that will be leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW, our primary regulator. The leases are designed to recover the capital costs of the plant including a return. PWGS 1 was placed in service in July 2005 and PWGS 2 was placed in service in May 2008. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

The Oak Creek expansion includes common projects that will benefit the existing units at this site as well as the new units. These projects include a coal handling facility and a water intake system. The costs associated with these projects are included under the OC 1 captions below. In November 2007, the coal handling system for Oak Creek was placed in service, and the water intake system was placed in service in January 2009.

During Construction:

Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for our PTF units. Our pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as

deferred revenue and will be amortized to revenue over the term of each lease once the respective unit is placed into service. During the construction of our PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest which was approximately 5% for the nine months ended September 30, 2009 and approximately 6% in 2008. Capitalized interest is included in the total cost of the PTF units shown below.

Cash Flows:

The following table identifies key pre-tax cash outflows and inflows for the nine months ended September 30 related to the construction of our PTF units as compared to Wisconsin Energy overall:

	Capital Expenditures (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$82.6	$60.1	$142.7	$555.8
2008	$ -	$48.3	$226.3	$177.0	$451.6	$888.9

	Capitalized Interest (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$33.0	$20.2	$53.2	$57.8
2008	$ -	$7.1	$36.2	$17.8	$61.1	$63.5

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$92.0	$56.4	$148.4	$148.4
2008	$ -	$16.9	$89.8	$44.4	$151.1	$151.1

Balance Sheet:

As noted above, we collect in current rates carrying costs that are calculated based on the cash expenditures included in CWIP multiplied by our pre-tax cost of capital. The carrying costs are recorded as deferred revenue and included in long-term liabilities. Our total CWIP balance includes cash expenditures, capitalized interest and accruals. The following table identifies key amounts related to our PTF units that were recorded on our balance sheet as of September 30, 2009 and December 31, 2008:

	CWIP - Cash Expenditures (Millions of Dollars)				Total
	PWGS 1	PWGS 2	OC 1	OC 2	PTF
September 30, 2009	$ -	$ -	$947.1	$571.8	$1,518.9
December 31, 2008	$ -	$ -	$952.9	$520.8	$1,473.7

	Total CWIP (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2009	$ -	$ -	$1,075.9	$642.6	$1,718.5	$2,062.1
December 31, 2008	$ -	$ -	$1,065.5	$571.3	$1,636.8	$1,829.9

	Net Plant in Service (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2009	$326.2	$354.1	$320.7	$ -	$1,001.0	$6,769.6
December 31, 2008	$332.7	$360.3	$194.0	$ -	$887.0	$6,596.5

	Deferred Revenue, net (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2009	$60.3	$74.9	$376.2	$176.5	$687.9	$687.9
December 31, 2008	$62.7	$77.3	$285.5	$119.9	$545.4	$545.4

Income Statement:

Once the PTF units are placed in service, we expect to recover in rates the lease costs which reflect the authorized cash construction costs of the units plus a return on the investment. The authorized cash costs are established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs are recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first five years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

We recognize revenues related to the lease payments that are included in our rates. In addition, our revenues include the amortization of the deferred revenues that reflect the carrying costs that are collected during construction. The deferred revenue is amortized over the lease term. We depreciate the units on a straight line basis over their expected service life.

In July 2005, PWGS 1 was placed in service. This asset had a cost of approximately $364.3 million, which included approximately $31.1 million of capitalized interest. The asset is being depreciated over its estimated useful life of 37 years. The cost of the plant, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $48 million.

In November 2007, the coal handling system for Oak Creek was placed into service. This asset had a cost of approximately $199.1 million. This asset is being depreciated over its estimated useful life of 40 years. The cost of the system, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 32 year period at an annual amount of approximately $24 million.

In May 2008, PWGS 2 was placed in service. This asset had a cost of approximately $366.0 million, which included approximately $34.0 million of capitalized interest. The asset is being depreciated over its estimated useful life of 37 years. The cost of the plant, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $49 million.

In January 2009, the new water intake system that serves both the existing units at Oak Creek and OC 1 and OC 2 was placed in service. This asset had a cost of approximately $132.5 million. This asset is being depreciated over its estimated useful life of 40 years. The cost of the system, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 31 year period at an annual amount of approximately $16 million.

4 -- COMMON EQUITY

Share-Based Compensation Expense:

For a description of share-based compensation, including stock options, restricted stock and performance units, see Note J -- 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, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to outstanding stock options during the period. Shares purchased on the open market by our independent agents are currently used to satisfy the exercise of share-based awards.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
	(Millions of Dollars)			
Stock options	$2.7	$2.9	$8.0	$8.8
Performance units	5.7	3.3	9.6	6.2
Restricted stock	0.2	0.2	0.7	0.8
Share-based compensation expense	$8.6	$6.4	$18.3	$15.8
Related Tax Benefit	$3.4	$2.5	$7.3	$6.3

Stock Option Activity:

During the first nine months of 2009, the Compensation Committee granted 1,216,625 options that had an estimated fair value of $8.01 per share. During the first nine months of 2008, the Compensation Committee granted 1,362,160 options that had an estimated fair value of $9.39 per share. The following assumptions were used to value the 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 our historical experience.

The following is a summary of our stock option activity for the three and nine months ended September 30, 2009:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of July 1, 2009	9,506,451	$37.93		
Granted	-			

Exercised	(239,563)	$26.10		
Forfeited	-			
Outstanding as of September 30, 2009	9,266,888	$38.24		

Outstanding as of January 1, 2009	8,543,564	$36.97		
Granted	1,216,625	$42.22		
Exercised	(485,941)	$25.75		
Forfeited	(7,360)	$46.09		
Outstanding as of September 30, 2009	9,266,888	$38.24	6.1	$71.6
Exercisable as of September 30, 2009	5,601,788	$33.14	4.7	$68.1

The intrinsic value of options exercised was $4.3 million and $8.2 million for the three and nine months ended September 30, 2009, and $2.5 million and $8.7 million for the same periods in 2008, respectively. Cash received from options exercised was $12.5 million and $10.0 million for the nine months ended

September 30, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $3.3 million and $2.9 million, respectively.

Stock options to purchase 2,718,965 shares of common stock, with prices ranging from $47.76 to $48.04 per share were outstanding during the first nine months of 2009, but were not included in the computation of diluted earnings per share because they were anti-dilutive.

The following table summarizes information about stock options outstanding as of September 30, 2009:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$19.62 to $31.07	1,696,468	$25.42	3.0	1,696,468	$25.42	3.0
$33.44 to $39.48	3,625,165	$35.66	5.2	3,625,165	$35.66	5.2
$42.22 to $48.04	3,945,255	$46.13	8.2	280,155	$47.33	7.5
	9,266,888	$38.24	6.1	5,601,788	$33.14	4.7

The following table summarizes information about our non-vested options during the three and nine months ended September 30, 2009:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of July 1, 2009	3,716,495	$8.72
Granted	-	
Vested	(51,395)	$8.46
Forfeited	-	
Non-vested as of September 30, 2009	3,665,100	$8.73
Non-vested as of January 1, 2009	3,598,379	$8.81
Granted	1,216,625	$8.01
Vested	(1,142,544)	$7.59
Forfeited	(7,360)	$8.73
Non-vested as of September 30, 2009	3,665,100	$8.73

As of September 30, 2009, total compensation costs related to non-vested stock options not yet recognized was approximately $10.2 million, which is expected to be recognized over the next 17 months on a weighted-average basis.

Restricted Shares:

The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during the three and nine months ended September 30, 2009:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of July 1, 2009	112,730	
Granted	-	
Released / Forfeited	(1,923)	$29.13

Outstanding as of September 30, 2009	110,807	

Outstanding as of January 1, 2009	116,373	
Granted	14,216	$42.11
Released / Forfeited	(19,782)	$35.30
Outstanding as of September 30, 2009	110,807	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. The intrinsic value of restricted stock vesting was $0.1 million and $0.8 million for the three and nine months ended September 30, 2009, and $0.2 million and $2.0 million for the same periods in 2008, respectively. The actual tax benefits realized for tax deductions associated with released restricted shares was zero and $0.3 million for the three and nine months ended September 30, 2009, and $0.1 million and $0.5 million for the same periods in 2008, respectively.

As of September 30, 2009, total compensation cost related to restricted stock not yet recognized was approximately $1.6 million, which is expected to be recognized over the next 30 months on a weighted-average basis.

Performance Units:

In January 2009 and 2008, the Compensation Committee granted 333,220 and 133,855 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three year period. We are accruing compensation costs over the three year period based on our estimate of the final expected value of each award. 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 $8.4 million and $5.2 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $3.1 million and $1.8 million, respectively. As of September 30, 2009, total compensation cost related to performance units not yet recognized was approximately $15.1 million, which is expected to be recognized over the next 23 months on a weighted-average basis.

Restrictions:

Wisconsin Energy's ability as a holding company to pay common dividends is primarily dependent upon the availability of funds received from its primary subsidiaries, Wisconsin Electric, Wisconsin Gas and We Power. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our principal utility subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note J --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 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. We recorded the following total comprehensive income, net of tax, during the nine months ended September 30:

Comprehensive Income	2009	2008
	(Millions of Dollars)	
Net Income	$263.7	$258.7
Other Comprehensive Income		
Hedging	0.3	0.3
Total Other Comprehensive Income	0.3	0.3
Total Comprehensive Income	$264.0	$259.0

5 -- LONG TERM DEBT

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of September 30, 2009, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

6 -- DISCONTINUED OPERATIONS

Effective April 30, 2009, we sold our water utility to the City of Mequon, Wisconsin for approximately $14.5 million.

The assets and liabilities associated with our water utility reclassified as held for sale within other current assets and liabilities on our Consolidated Condensed Balance Sheets as of December 31, 2008 were $14.4 million and $0.3 million, respectively. We also reclassified the water utility income as discontinued operations in the accompanying Consolidated Condensed Income Statements.

The following table summarizes the net impacts of the discontinued operations on our earnings as of September 30, 2009 and 2008:

	Three Months	Nine Months

	Ended September 30		Ended September 30	
	2009	2008	2009 (a)	2008
	(Millions of Dollars)			
Income from Continuing Operations	$58.7	$76.6	$263.6	$257.8
Income from Discontinued water operations, net of tax	-	0.3	0.4	0.7
Income (Loss) from Discontinued other operations, net of tax	(0.2)	0.6	(0.3)	0.2
Net Income	$58.5	$77.5	$263.7	$258.7

(a) As a result of its sale effective April 30, 2009, we operated the water utility for four of the nine months ended September 30, 2009.

Cash provided by operating activities in our Consolidated Condensed Statements of Cash Flows reflects income from discontinued water operations, net of tax, of $0.5 million and $0.9 million for the nine

months ended September 30, 2009 and 2008, respectively. Cash used in investing activities reflects activity from discontinued water operations of $0.1 million and $0.5 million for the nine months ended September 30, 2009 and 2008, respectively. Discontinued water operations had no material impact on financing activities for the nine months ended September 30, 2009 and 2008.

7 -- 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.

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 September 30, 2009			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$237.0	$ -	$ -	$237.0
Derivatives	4.6	7.2	10.2	22.0
Total	$241.6	$7.2	$10.2	$259.0
Liabilities:				
Derivatives	$6.3	$4.3	$ -	$10.6
Total	$6.3	$4.3	$ -	$10.6

Recurring Fair Value Measures	As of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Cash Equivalents	$9.1	$ -	$ -	$9.1

Restricted Cash	386.5	-	-	386.5
Derivatives	-	4.2	8.8	13.0
Total	$395.6	$4.2	$8.8	$408.6
Liabilities:				
Derivatives	$38.9	$32.1	$ -	$71.0
Total	$38.9	$32.1	$ -	$71.0

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 July 1	$15.5	$21.5
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	(5.3)	(6.8)
Transfers in and/or out of Level 3	-	-
Balance as of September 30	$10.2	$14.7
Change in unrealized gains (losses) relating to instruments still held as of September 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	1.4	1.7
Transfers in and/or out of Level 3	-	-
Balance as of September 30	$10.2	$14.7
Change in unrealized gains (losses) relating to instruments still held as of September 30	$ -	$ -

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 8 -- 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:

	September 30, 2009		December 31, 2008	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$20.2	$30.4	$19.0
Long-term debt including current portion	$3,818.8	$3,944.6	$4,009.4	$3,711.9

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases and unamortized discount 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.

8 -- 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 September 30, 2009, we recognized $23.6 million in regulatory assets and $17.5 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 and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

We record our current derivative assets on the balance sheet in Prepayments and other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative assets of $1.0 million is recorded in Other deferred charges and other assets and the long-term portion of our derivative liabilities of $4.3 million is recorded in Other deferred credits and other liabilities. Our Consolidated Condensed Balance Sheet as of September 30, 2009 includes:

	Derivative Asset	Derivative Liability
	(Millions of Dollars)	
Natural Gas	$7.0	$10.6
Fuel Oil	0.5	-
FTRs	10.3	-
Coal	4.2	-
Total	$22.0	$10.6

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

	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	21.4 million Dth	($26.4)	67.1 million Dth	($80.0)
Energy	8,400 MWh	-	23,520 MWh	(0.6)
Fuel Oil	2.1 million gallons	(0.5)	5.1 million gallons	(2.3)
FTRs	6,659 MW	1.2	21,432 MW	6.4
Total		($25.7)		($76.5)

As of September 30, 2009 we have posted collateral of $12.5 million in our margin accounts.

9 -- BENEFITS

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

	Pension Benefits		OPEB	
Benefit Plan Cost Components	2009	2008	2009	2008
	(Millions of Dollars)			
Three Months Ended September 30				
Net Periodic Benefit Cost				
Service cost	$5.7	$4.4	$2.2	$2.6
Interest cost	18.1	17.8	5.1	5.0
Expected return on plan assets	(23.8)	(21.2)	(3.4)	(4.4)
Amortization of:				
Transition obligation	-	-	0.1	-
Prior service cost (credit)	0.6	0.6	(3.1)	(3.1)
Actuarial loss	4.7	4.1	2.2	1.6
Net Periodic Benefit Cost	$5.3	$5.7	$3.1	$1.7
Nine Months Ended September 30				
Net Periodic Benefit Cost				
Service cost	$17.4	$13.1	$6.5	$7.8
Interest cost	54.2	53.3	15.4	15.0
Expected return on plan assets	(71.5)	(63.6)	(10.2)	(13.2)
Amortization of:				
Transition obligation	-	-	0.2	0.2
Prior service cost (credit)	1.7	1.9	(9.4)	(9.4)
Actuarial loss	14.1	12.3	6.7	4.5
Net Periodic Benefit Cost	$15.9	$17.0	$9.2	$4.9

In January 2009, we contributed $289.3 million to our 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 Trustee of our pension plan to invest in the commercial paper of Wisconsin Energy. As of September 30, 2009, the Pension Trust held approximately $84 million of commercial paper issued by Wisconsin Energy, which represents less than 10% of total assets of the plan.

10 -- GUARANTEES

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

	Maximum Potential Future Payments	Outstanding	Liability Recorded
		(Millions of Dollars)	
Wisconsin Energy			
Non-Utility Energy	$ -	$ -	$ -
Other	0.2	0.2	-
Wisconsin Electric	2.9	0.1	-
Total	$3.1	$0.3	$ -

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to PSEG, provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement for Wisvest-Connecticut with The United Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

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

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

Postemployment benefits:

Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $17.8 million as of September 30, 2009 and $18.6 million as of December 31, 2008.

11 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable operating segments for the three and nine month periods ended September 30, 2009 and 2008 is shown in the following table:

	Reportable Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
		(Millions of Dollars)		
Three Months Ended				
September 30, 2009				
Operating Revenues (b)	$817.5	$44.3	($39.9)	$821.9
Depreciation, Decommissioning and Amortization	$79.8	$7.3	$0.2	$87.3
Operating Income (Loss)	$74.9	$32.5	($2.5)	$104.9
Equity in Earnings of Unconsolidated Affiliates	$14.9	$ -	($0.1)	$14.8
Interest Expense, net	$29.0	$3.4	$6.0	$38.4
Income Tax Expense (Benefit)	$24.4	$11.6	($2.9)	$33.1
Income (Loss) from Discontinued Operations, Net of Tax	$ -	$ -	($0.2)	($0.2)
Net Income (Loss)	$46.0	$17.4	($4.9)	$58.5
Capital Expenditures	$128.2	$62.4	$ -	$190.6

	Reportable Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
		(Millions of Dollars)		
Three Months Ended				

September 30, 2008				
Operating Revenues (b)	$846.5	$40.1	($35.1)	$851.5
Depreciation, Decommissioning and Amortization	$77.4	$6.3	$0.3	$84.0
Operating Income (Loss)	$112.3	$28.9	($2.8)	$138.4
Equity in Earnings of Unconsolidated Affiliates	$14.4	$ -	$0.4	$14.8
Interest Expense, net	$25.4	$4.2	$9.2	$38.8
Income Tax Expense (Benefit)	$39.6	$10.4	($5.5)	$44.5
Income from Discontinued Operations, Net of Tax	$0.3	$ -	$0.6	$0.9
Net Income (Loss)	$68.1	$15.3	($5.9)	$77.5
Capital Expenditures	$135.6	$111.2	$0.1	$246.9

<u>Nine Months Ended</u>

September 30, 2009				
Operating Revenues (b)	$3,053.0	$125.1	($117.5)	$3,060.6
Depreciation, Decommissioning and Amortization	$237.1	$21.8	$0.5	$259.4
Operating Income (Loss)	$381.4	$91.2	($5.5)	$467.1
Equity in Earnings of Unconsolidated Affiliates	$43.6	$ -	($0.1)	$43.5
Interest Expense, net	$88.6	$11.6	$18.8	$119.0
Income Tax Expense (Benefit)	$129.2	$33.5	($10.6)	$152.1
Income (Loss) from Discontinued Operations, Net of Tax	$0.4	$ -	($0.3)	$0.1
Net Income (Loss)	$229.8	$47.9	($14.0)	$263.7
Capital Expenditures	$403.1	$147.1	$5.6	$555.8
Total Assets (c)	$10,539.5	$2,688.3	($807.1)	$12,420.7

<u>Nine Months Ended</u>

September 30, 2008				
Operating Revenues (b)	$3,222.5	$91.8	($86.3)	$3,228.0
Depreciation, Decommissioning and Amortization	$226.1	$15.3	$0.7	$242.1
Operating Income (Loss)	$408.7	$63.1	($8.0)	$463.8
Equity in Earnings of Unconsolidated Affiliates	$38.0	$ -	($0.3)	$37.7
Interest Expense, net	$78.1	$7.9	$27.4	$113.4
Income Tax Expense (Benefit)	$147.6	$23.4	($14.8)	$156.2

Income from Discontinued Operations, Net of Tax	$0.7	$ -	$0.2	$0.9
Net Income (Loss)	$241.9	$34.6	($17.8)	$258.7
Capital Expenditures	$435.4	$453.2	$0.3	$888.9
Total Assets (c)	$10,189.2	$2,455.6	($855.4)	$11,789.4

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

(b) An elimination for intersegment revenues of $39.9 million and $35.2 million for the three months ended September 30, 2009 and 2008, respectively, and $117.6 million and $85.5 million for the nine months ended September 30, 2009 and 2008, respectively, is included in Operating Revenues.

(c) An elimination of $883.4 million and $786.0 million is included in Total Assets at September 30, 2009 and 2008, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

12 -- 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 $430.8 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 September 30, 2009 and December 31, 2008, were $47.9 million and $66.4 million, respectively.

13 -- 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.

Divestitures:

Over the past several years, we have sold various businesses and assets. In connection with these sales, we have agreed to provide the respective buyers with customary indemnification provisions including, but not limited to, certain environmental, asbestos and product liability matters. In addition, pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We have established reserves as deemed appropriate for these indemnification provisions.

14 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2009, we paid $70.4 million in interest, net of amounts capitalized, and $1.9 million in income taxes, net of refunds. During the nine months ended September 30, 2008, we paid $96.1 million in interest, net of amounts capitalized, and $2.4 million in income taxes, net of refunds.

As of September 30, 2009 and 2008, the amount of accounts payable related to capital expenditures was $56.6 million and $55.9 million, respectively.

15 -- ASSET SALE -- SUBSEQUENT EVENT

In October 2009, we entered into an agreement to sell Edison Sault to Cloverland Electric Cooperative for approximately $61.5 million. We will retain the membership interest in ATC currently held by Edison Sault. The sale is contingent upon certain conditions, including the approval by regulatory bodies. If the conditions are satisfied, we expect the sale to be completed in 2010.

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

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

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the third quarter of 2009 with the third quarter of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended September 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Utility Energy Segment	$74.9	($37.4)	$112.3
Non-Utility Energy Segment	32.5	3.6	28.9
Corporate and Other	(2.5)	0.3	(2.8)
Total Operating Income	104.9	(33.5)	138.4
Equity in Earnings of Transmission Affiliate	14.9	0.5	14.4
Other Income, net	10.4	3.3	7.1
Interest Expense, net	38.4	0.4	38.8
Income from Continuing Operations Before Income Taxes	91.8	(29.3)	121.1
Income Taxes	33.1	11.4	44.5
Income from Continuing Operations	58.7	(17.9)	76.6
Income (Loss) from Discontinued Operations, Net of Tax	(0.2)	(1.1)	0.9
Net Income	$58.5	($19.0)	$77.5
Diluted Earnings Per Share	$0.50	($0.15)	$0.65

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $74.9 million of operating income during the third quarter of 2009, a decrease of $37.4 million, or 33.3%, compared with the third quarter of 2008. The following table summarizes the operating income of this segment between the comparative quarters:

Utility Energy Segment	Three Months Ended September 30 2009	B (W)	2008
	(Millions of Dollars)		
Operating Revenues			
Electric	$689.1	$4.2	$684.9
Gas	122.5	(33.6)	156.1
Other	5.9	0.4	5.5
Total Operating Revenues	817.5	(29.0)	846.5
Fuel and Purchased Power	293.8	51.4	345.2
Cost of Gas Sold	63.2	32.6	95.8
Gross Margin	460.5	55.0	405.6
Other Operating Expenses			
Other Operation and Maintenance	335.9	11.0	346.9
Depreciation, Decommissioning and Amortization	79.8	(2.4)	77.4
Property and Revenue Taxes	27.8	(1.4)	26.4
Total Operating Expenses	800.5	91.2	891.7
Amortization of Gain	57.9	(99.5)	157.4
Operating Income	$74.9	($37.4)	$112.3

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the third quarter of 2009 with the third quarter of 2008:

	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$245.3	($18.7)	$264.0	2,015.3	(230.0)	2,245.3
Small Commercial/Industrial	230.5	(15.3)	245.8	2,338.0	(173.0)	2,511.0
Large Commercial/Industrial	166.4	(12.6)	179.0	2,487.8	(392.6)	2,880.4
Other - Retail	4.9	(0.1)	5.0	36.8	(2.0)	38.8

Total Retail	647.1	(46.7)	693.8	6,877.9	(797.6)	7,675.5
Wholesale - Other	20.9	55.5	(34.6)	167.1	(372.9)	540.0
Resale - Utilities	7.7	(7.7)	15.4	282.7	(44.1)	326.7
Other Operating	13.4	3.1	10.3	-	-	-
Total	$689.1	$4.2	$684.9	7,327.7	(1,214.6)	8,542.2
Weather -- Degree Days (a)						
Heating (130 Normal)				124	53	71
Cooling (520 Normal)				341	(137)	478

(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 a net $4.2 million, or 0.6%, when compared to the third quarter of 2008. The most significant factors that caused a change in revenues were:

- A one-time FERC-approved refund to our wholesale customers in 2008 associated with their share of the gain on the sale of Point Beach that reduced 2008 wholesale revenues by $62.5 million.
- 2009 pricing increases totaling approximately $37.0 million reflecting the reduction of Point Beach credits to retail customers.

- 2009 pricing decreases totaling approximately $18.4 million related to a reduction in electric rates as a result of the PSCW approval in April 2009 of our fuel cost decrease filing.
- Unfavorable summer weather that reduced electric revenues by an estimated $32.9 million as compared to the third quarter of 2008.
- A slowdown in the economy that reduced commercial and industrial sales by an estimated $34.0 million and wholesale sales by an estimated $8.6 million as compared to the third quarter of 2008.

Our total electric sales volumes decreased by approximately 14.2% as compared to third quarter of 2008 due almost exclusively to a continued decline in economic conditions, which primarily affected our commercial and industrial sales, and cooler summer weather, which primarily affected our residential sales. Total retail sales declined nearly 10.4%. Of the 10.4% decline in retail sales, approximately 7.4% relates to sales volumes at our small and large commercial and industrial customers. As measured by cooling degree days, the third quarter of 2009 was 28.7% cooler than the third quarter of 2008 and 34.4% cooler than normal.

For the fourth quarter of 2009, we expect to see a continued decline in electric sales to commercial and industrial customers as compared to the same period in 2008 as a result of the downturn in the economy. We also expect to continue to see a reduction in revenues as a result of the PSCW approval in April 2009 of our request to decrease Wisconsin retail rates due to a decrease in fuel and purchased power costs, 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 -- Utility Rates and Regulatory Matters -- 2009 Fuel Cost

Decrease Filing.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $51.4 million, or 14.9%, when compared to the third 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 third quarter of 2009 with the third 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 $33.6 million, or 21.5%, primarily due to lower natural gas prices.

	Three Months Ended September 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	$122.5	($33.6)	$156.1
Cost of Gas Sold	63.2	32.6	95.8
Gross Margin	$59.3	($1.0)	$60.3

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

	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$36.5	$0.9	$35.6	49.4	3.3	46.1
Commercial/Industrial	10.3	0.3	10.0	33.3	0.6	32.7
Interruptible	0.4	(0.1)	0.5	2.8	(1.3)	4.1

Total Retail	47.2	1.1	46.1	85.5	2.6	82.9
Transported Gas	10.7	(0.1)	10.8	186.7	(1.5)	188.2
Other	1.4	(2.0)	3.4	-	-	-
Total	$59.3	($1.0)	$60.3	272.2	1.1	271.1
Weather -- Degree Days (a)						
Heating (130 Normal)				124	53	71

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

Our gas margins are seasonal and are primarily driven by the heating needs of our customers. The third quarter gas margins are historically the lowest of the year because of the lack of heating load. Our gas margins decreased by $1.0 million, or 1.7%, when compared to the third quarter of 2008.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $11.0 million, or approximately 3.2%, when compared to the third quarter of 2008. This decrease is primarily related to reduced operating and maintenance expenses at our power plants and electric distribution system.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by $2.4 million, or approximately 3.1%, when compared to the third quarter of 2008. This increase was the result of higher depreciation related to new projects.

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 three months ended September 30:

Amortization of Gain	2009	2008
	(Millions of Dollars)	

Bill Credits - Retail	$57.9	$94.9
One-Time FERC-Approved Wholesale Refund	-	62.5
Total Amortization of Gain	$57.9	$157.4

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $32.5 million of operating income for the third quarter of 2009 as compared to $28.9 million for the third quarter of 2008. The increase primarily relates to earnings from the water intake system for Oak Creek that was placed into service in January 2009.

CONSOLIDATED OTHER INCOME, NET

Other income, net increased by approximately $3.3 million, when compared to the third quarter of 2008 because of higher interest income and an increase in AFUDC - Equity related to the Oak Creek AQCS project. For further information on the Oak Creek AQCS project, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System Approval. These increases were partially offset by reduced property sales during the third quarter of 2009 as compared to the same period in 2008.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended September 30	
Interest Expense	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	$58.0	$59.1
Less: Capitalized Interest	19.6	20.3
Interest Expense, net	$38.4	$38.8

Our gross interest costs decreased by $1.1 million, or 1.9%, during the third quarter of 2009 as compared to the same period in 2008, and our capitalized interest decreased by $0.7 million between the comparative periods, primarily due to lower short-term interest rates. As a result, our net interest expense decreased by $0.4 million, or 1.0%, as compared to the third quarter of 2008.

CONSOLIDATED INCOME TAXES

For the third quarter of 2009, our effective tax rate applicable to continuing operations was 36.1% compared to 36.7% for the third quarter of 2008. For additional information, see Note H -- Income Taxes in our 2008 Annual Report on Form 10-K. We expect our 2009 annual effective tax rate to be between 35.0% and 37.0%.

RESULTS OF OPERATIONS -- NINE MONTHS ENDED SEPTEMBER 30, 2009

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first nine months of 2009 with the first nine months of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Nine Months Ended September 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Utility Energy Segment	$381.4	($27.3)	$408.7
Non-Utility Energy Segment	91.2	28.1	63.1
Corporate and Other	(5.5)	2.5	(8.0)
Total Operating Income	467.1	3.3	463.8
Equity in Earnings of Transmission Affiliate	43.6	5.6	38.0
Other Income, net	24.0	(1.6)	25.6
Interest Expense, net	119.0	(5.6)	113.4
Income from Continuing Operations Before Income Taxes	415.7	1.7	414.0
Income Taxes	152.1	4.1	156.2
Income from Continuing Operations	263.6	5.8	257.8
Income from Discontinued Operations, Net of Tax	0.1	(0.8)	0.9
Net Income	$263.7	$5.0	$258.7
Diluted Earnings Per Share	$2.24	$0.05	$2.19

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $381.4 million of operating income during the first nine months of 2009, a decrease of $27.3 million, or 6.7%, compared with the first nine months of 2008. The following table summarizes the operating income of this segment between the comparative periods:

	Nine Months Ended September 30		
Utility Energy Segment	2009	B (W)	2008
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,033.8	$11.8	$2,022.0
Gas	991.0	(180.7)	1,171.7
Other	28.2	(0.6)	28.8
Total Operating Revenues	3,053.0	(169.5)	3,222.5
Fuel and Purchased Power	816.2	167.3	983.5
Cost of Gas Sold	667.9	173.6	841.5
Gross Margin	1,568.9	171.4	1,397.5
Other Operating Expenses			
Other Operation and Maintenance	1,043.8	41.8	1,085.6
Depreciation, Decommissioning and Amortization	237.1	(11.0)	226.1
Property and Revenue Taxes	83.8	(3.3)	80.5
Total Operating Expenses	2,848.8	368.4	3,217.2
Amortization of Gain	177.2	(226.2)	403.4
Operating Income	$381.4	($27.3)	$408.7

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Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first nine months of 2009 with the first nine months of 2008:

	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		

Customer Class						
Residential	$739.6	$7.2	$732.4	6,029.1	(303.0)	6,332.1
Small Commercial/Industrial	672.7	(4.8)	677.5	6,721.7	(345.6)	7,067.3
Large Commercial/Industrial	458.8	(50.0)	508.8	6,930.8	(1,493.4)	8,424.2
Other - Retail	15.7	0.2	15.5	117.4	(4.5)	121.9
Total Retail	1,886.8	(47.4)	1,934.2	19,799.0	(2,146.5)	21,945.5
Wholesale - Other	73.3	43.9	29.4	879.4	(854.0)	1,733.4
Resale - Utilities	31.5	2.0	29.5	974.2	334.1	640.1
Other Operating	42.2	13.3	28.9	-	-	-
Total	$2,033.8	$11.8	$2,022.0	21,652.6	(2,666.4)	24,319.0
Weather -- Degree Days (a)						
Heating (4,324 Normal)				4,528	(58)	4,586
Cooling (688 Normal)				475	(112)	587

(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 a net $11.8 million, or 0.6%, when compared to the first nine months of 2008. The most significant factors that caused a change in revenues were:

- A one-time FERC-approved refund to our wholesale customers in 2008 associated with their share of the gain on the sale of Point Beach that reduced 2008 wholesale revenues by $62.5 million.
- 2009 pricing increases totaling approximately $78.7 million reflecting the reduction of Point Beach credits to retail customers.
- Net pricing increases totaling approximately $22.3 million related to Wisconsin and Michigan rate orders.
- Unfavorable weather that reduced electric revenues by an estimated $27.8 million as compared to the first nine months of 2008.
- A slowdown in the economy that reduced commercial and industrial sales by an estimated $115.6 million and wholesale sales by an estimated $24.6 million.

Our total electric sales volumes decreased by approximately 11.0% as compared to the first nine months of 2008 due almost exclusively to a continued decline in economic conditions, which primarily affected our commercial and industrial sales, and milder weather, which primarily affected our residential sales. Total retail sales declined nearly 9.8%. Of the 9.8% decline in retail sales, approximately 8.4% relates to sales volumes at our small and large commercial and industrial customers. As measured by cooling degree days, the first nine months of 2009 was 19.1% cooler than the same period in 2008 and 31.0% cooler than normal.

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

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $167.3 million, or 17.0%, when compared to the first nine months of 2008. This decline was primarily caused by lower MWh sales and lower natural gas and purchased power prices, partially offset by higher coal and transportation costs. Approximately $41.2 million of the decrease related to a 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 $126.1 million, or 12.8%.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first nine months of 2009 with the first nine 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 $180.7 million, or 15.4%, primarily due to lower natural gas prices and milder weather.

	Nine Months Ended September 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	$991.0	($180.7)	$1,171.7
Cost of Gas Sold	667.9	173.6	841.5
Gross Margin	$323.1	($7.1)	$330.2

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

	Nine Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$206.0	($0.5)	$206.5	550.9	(7.3)	558.2
Commercial/Industrial	72.8	(2.0)	74.8	328.7	(11.0)	339.7
Interruptible	1.4	(0.4)	1.8	13.8	(3.3)	17.1
Total Retail	280.2	(2.9)	283.1	893.4	(21.6)	915.0
Transported Gas	36.0	(2.4)	38.4	658.9	(11.3)	670.2
Other	6.9	(1.8)	8.7	-	-	-
Total	$323.1	($7.1)	$330.2	1,552.3	(32.9)	1,585.2

Weather -- Degree Days (a)			
Heating (4,324 Normal)	4,528	(58)	4,586

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

Our gas margins decreased by $7.1 million, or 2.2%, when compared to the first nine months of 2008. We estimate that a decline in sales volumes as a result of milder winter weather and a decline in economic conditions caused margins to decrease by approximately $8.1 million during the first nine months of 2009 as compared to the same period in 2008. As measured by heating degree days, the first nine months of 2009 were 1.3% warmer than the same period in 2008, but 4.7% 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 nine months in 2009 partially offset this decrease.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by approximately $41.8 million, or 3.9%, when compared to the first nine months of 2008. The largest factor for this decrease relates to a $43.8 million one-time amortization of deferred bad debts 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 nine 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 $15.9 million higher in the first nine months of 2009 as compared to the same period in 2008. The remaining decrease is primarily related to reduced operating and maintenance expenses at our power plants and electric distribution system.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by $11.0 million, or approximately 4.9%, when compared to the first nine months of 2008. This increase was the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project which 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 nine months ended September 30:

Amortization of Gain	2009	2008

	(Millions of Dollars)	
Bill Credits - Retail	$177.2	$255.9
One-Time Amortization	-	85.0
One-Time FERC-Approved Wholesale Refund	-	62.5
Total Amortization of Gain	$177.2	$403.4

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $91.2 million of operating income for the first nine months of 2009 as compared to $63.1 million for the first nine months of 2008. The increase primarily relates to nine months of earnings from PWGS 2, which was placed into service in May 2008, and the earnings from the water intake system at Oak Creek which was placed into service in January 2009.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by approximately $1.6 million, or 6.3%, when compared to the first nine months of 2008. This decrease primarily relates to reduced property sales during the first nine months of 2009 as compared to the same period in 2008. This decrease was partially offset by an increase in

AFUDC - Equity related to the Oak Creek AQCS project. For further information on the Oak Creek AQCS project, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters - Oak Creek Air Quality Control System Approval.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Nine Months Ended September 30	
	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	$176.8	$176.9
Less: Capitalized Interest	57.8	63.5
Interest Expense, net	$119.0	$113.4

Our gross interest costs decreased by $0.1 million during the nine months ended September 30, 2009 as compared to the same period in 2008, and our capitalized interest decreased by $5.7 million between the comparative periods, primarily due to lower short-term interest rates. As a result, our net interest expense increased by $5.6 million, or 4.9%, as compared to the first nine months of 2008.

CONSOLIDATED INCOME TAXES

For the first nine months of 2009, our effective tax rate applicable to continuing operations was 36.6% compared to 37.7% for the first nine months of 2008. For additional information, see Note H -- Income Taxes in our 2008 Annual Report on Form 10-K. We expect our 2009 annual effective tax rate to be between 35.0% and 37.0%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the first nine months of 2009 and 2008:

	Nine Months Ended September 30	
Wisconsin Energy Corporation	2009	2008
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$436.5	$643.0
Investing Activities	($478.6)	($681.7)
Financing Activities	$20.3	$34.6

Operating Activities

Cash provided by operating activities was $436.5 million during 2009, which was $206.5 million lower than 2008. Although we experienced an increase in net income and depreciation during the first nine months of 2009, there were two large factors that reduced cash from operations. During the first nine months of 2009, we contributed $289.3 million to our benefit plans as compared to approximately $48.4 million

during the first nine months of 2008. The second factor related to an increase in cash used for working capital related to our coal inventories.

Investing Activities

Cash used in investing activities was $478.6 million during the nine months ended September 30, 2009, which was $203.1 million lower than the same period in 2008. This decline primarily reflects lower capital expenditures during the first nine months of 2009 and cash flows from the release of restricted cash.

During the first nine months of 2009, our capital expenditures decreased $333.1 million, primarily due to the reduction in the capital expenditures for our Oak Creek expansion and the completion of PWGS 2 in 2008.

During the first nine months of 2009, we released $131.2 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.

Financing Activities

Cash provided by financing activities during the nine months ended September 30, 2009 was $20.3 million, compared to $34.6 million during the same period in 2008. During the first nine months of 2009, we paid approximately $118.4 million in cash dividends and Wisconsin Electric repurchased $147 million of outstanding tax-exempt bonds in August 2009. For more information about this repurchase, see Note 5 -- Long Term Debt in this report. Overall, we increased our debt levels by a net amount of approximately $145.2 million.

During the first nine months of 2009, we received proceeds of $12.5 million related to the exercise of stock options, compared with $10.0 million during the same period in 2008. Instead of issuing new shares for these stock options, we instructed our plan agent to purchase common stock in the open market at a cost of $21.0 million, compared with $19.9 million during the first nine months of 2008. This cost is included in Purchase of common stock on our Consolidated Condensed Statements of Cash Flows.

CAPITAL RESOURCES AND REQUIREMENTS

Capital Resources

We anticipate meeting our capital requirements during the remaining three 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. Beyond 2009, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings and the issuance of debt securities.

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

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

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, provided approximately $80 million of commitments under our bank back-up credit facilities on a consolidated basis. We have no current plans to replace Lehman's commitments. Excluding Lehman's commitments, as of September 30, 2009, we had approximately $1.6 billion of available, undrawn lines under our bank back-up credit facilities. As of September 30, 2009, we had approximately $938.0 million of short-term debt outstanding on a consolidated basis 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 facilities as of September 30, 2009:

Company	Total Facility *	Letters of Credit	Credit Available *	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$857.5	$1.1	$856.4	April 2011
Wisconsin Electric	$476.4	$4.4	$472.0	March 2011
Wisconsin Gas	$285.8	$ -	$285.8	March 2011

* Excludes Lehman's commitments

The following table shows our actual capitalization structure as of September 30, 2009, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the majority of rating agencies currently view the Junior Notes:

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$3,486.9	$3,736.9
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	3,943.7	3,693.7
Short-Term Debt	938.0	938.0
Total Capitalization	$8,399.0	$8,399.0
Total Debt	$4,881.7	$4,631.7
Ratio of Debt to Total Capitalization	58.1%	55.1%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of September 30, 2009 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of September 30, 2009, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

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 the debt securities and preferred stock of our subsidiaries by S&P, Moody's and Fitch as of September 30, 2009:

	S&P	Moody's	Fitch
Wisconsin Energy			
Commercial Paper	A-2	P-2	F2
Unsecured Senior Debt	BBB+	A3	A-
Unsecured Junior Notes	BBB-	Baa1	BBB+
Wisconsin Electric			
Commercial Paper	A-2	P-1	F1
Secured Senior Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A
Wisconsin Gas			
Commercial Paper	A-2	P-1	F1
Unsecured Senior Debt	A-	A1	A+
Wisconsin Energy Capital Corporation			
Unsecured Debt	BBB+	A3	A-

In July 2009, S&P affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and revised the ratings outlooks assigned to each company from positive to stable.

In June 2009, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and the stable ratings outlook of Wisconsin Gas. Fitch also revised the ratings outlooks of Wisconsin Energy, Wisconsin Electric and Wisconsin Energy Capital Corporation from stable to negative.

The security ratings outlooks assigned by Moody's for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are all stable.

Subject to other factors affecting the credit markets as a whole, we believe these security ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

Capital requirements during the remainder of 2009 are expected to be principally for capital expenditures related to the Oak Creek expansion and environmental controls at our existing Oak Creek generating units. Our 2009 annual consolidated capital expenditure budget is approximately $875 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 construction projects, 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 10 -- Guarantees and Note 12 -- 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 $22.0 billion as of September 30, 2009 compared with $23.1 billion as of December 31, 2008. Our total contractual obligations and other commercial commitments as of September 30, 2009 decreased compared with December 31, 2008, primarily due to periodic payments related to these types of obligations which were greater than new commitments made in the ordinary course of business during the nine month period ended September 30, 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, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion. We Power is leasing the PWGS units to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the lease payments in its electric rates. The Oak Creek expansion is currently being constructed by We Power, and we expect Wisconsin Electric to recover future lease payments in its 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 us 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 us 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.

We 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 first claim is based on the alleged impact of severe weather and certain labor-related matters. Bechtel is requesting approximately $413 million in costs related to changed weather and labor conditions. Bechtel has reserved the right to request future additional costs and schedule relief.

The weather events for which Bechtel seeks cost and schedule relief are (i) extreme winds from September 2006 through April 2007, (ii) snowstorms from December 2007 through April 2008, and (iii) rain storms in June 2008. Bechtel contends that these weather events constituted events of force majeure. We are continuing to analyze Bechtel's force majeure claim as we receive additional information to determine whether Bechtel is entitled to any schedule relief as a result of these weather events. However, we currently believe Bechtel's request for cost relief related to its claim of force majeure is without merit. Bechtel also claims that these same weather events constituted changed local conditions that could not have reasonably been foreseen and that caused it to incur additional costs. We believe that the claim for additional costs and schedule relief based on a change in local conditions is without merit.

The alleged changes in labor conditions for which Bechtel seeks cost and schedule relief are (i) a significant shortage in the availability of craft labor, (ii) significant increases in competing projects, (iii) the overtime and per diems allegedly necessary to attract labor, and (iv) alleged restrictions that our Project Labor Agreement placed on Bechtel's ability to attract and retain craft labor. Bechtel describes these as changed local conditions for which it believes we should bear the risk. Under the terms of the contract, we agreed to accept labor-related risk only as to wage escalation in excess of 4% annually as measured by published wage bulletins. Therefore, we believe that this claim is without merit.

Bechtel's second claim of approximately $72 million seeks cost and schedule relief for the alleged effects of ERS-directed changes and delays allegedly caused by ERS prior to the issuance of the FNTP in July 2005 as follows: (i) the delay in issuing certain limited notices to proceed; (ii) the delay in issuing the FNTP until the final resolution of litigation brought by certain opposition groups that challenged the CPCN for the Oak Creek expansion; (iii) the imposition of additional limits to third party cancellation charges which allegedly restricted Bechtel's ability to issue purchase orders; (iv) the reduction of the pre-FNTP monthly payments below the amounts required by the contract; and (v) the request by ERS to perform design studies and issue design changes during the pre-FNTP period. We believe that this claim is without merit. We currently believe Bechtel was fully compensated for any and all impacts of the delayed start as indicated in certain change orders entered into between ERS and Bechtel prior to the start of construction of the Oak Creek expansion. Further, we do not believe that the contract provides for relief based upon the cumulative impact of change orders.

We continue to believe that the only circumstances and events for which we currently retain price adjustment risk under the contract are force majeure, wage escalation in excess of 4% annually as measured by published wage bulletins, delays caused by us, changes in scope or performance requested by us and unforeseen sub-surface ground conditions.

Based on Bechtel's July 2008 communication, we notified Bechtel on September 29, 2008 that we were 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 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 anticipate will be concluded in 2010 or early 2011.

Bechtel continues to target an in-service date for unit 1 of December 29, 2009, which is three months beyond the guaranteed contract date, and an in-service date for unit 2 of August 29, 2010, which is one

month earlier than the guaranteed contract date. Although Bechtel has fallen slightly behind these dates, it has recovery plans in place and believes these target dates are achievable. However, the final few months of start-up and commissioning could present unforeseen challenges that may delay the in-service date of unit 1 beyond December 29, 2009.

UTILITY RATES AND REGULATORY MATTERS

2010 Rate Case:

On March 13, 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric initially asked the PSCW to approve a rate increase for its Wisconsin retail electric customers of approximately $76.5 million, or 2.8%, and a rate increase for its natural gas customers of approximately $22.1 million, or 3.6%. In addition, Wisconsin Electric has requested increases of approximately $1.4 million, or 5.8%, and approximately $1.3 million, or 6.8%, for its Valley steam utility customers and Milwaukee County steam utility customers, respectively. Wisconsin Gas has asked the PSCW to approve a rate increase for its natural gas customers of approximately $38.9 million, or 4.6%. Both Wisconsin Electric and Wisconsin Gas have requested that these rates become effective January 1, 2010.

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

Included as part of Wisconsin Electric's rate increase request for its retail electric customers are costs associated with certain projects contemplated in the settlement agreement we and the other two joint owners of the Oak Creek expansion entered into in July 2008 with Clean Wisconsin, Inc. and the Sierra Club to resolve litigation related to the WPDES permit for the cooling water intake system at the Oak Creek expansion. As part of the agreement, we agreed to seek regulatory approval to recover our share of the costs of these projects. In turn, Clean Wisconsin and the Sierra Club agreed to withdraw their opposition to the modified WPDES permit issued in May 2008 and, assuming regulatory approval to recover the project costs in rates, to not oppose or challenge (subject to limited exceptions) future issuances or renewals of environmental permits required to start-up or commence commercial operation of the Oak Creek expansion.

As part of its electric rate proceeding, Wisconsin Electric has 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.
- ♦ Wisconsin Electric will continue to receive 100% AFUDC for capital expenditures on environmental control projects at its 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, Wisconsin Electric 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.

Our 2010 rate case proceeding has completed technical and public hearings and briefs have been submitted.

2010 Michigan Price Increase Request:

In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. Pursuant to recently enacted Michigan legislation, we believe that we are allowed, upon the satisfaction of certain conditions, to self implement a rate increase request, subject to refund with interest. Therefore, we expect a portion of the rate increase to be effective in early 2010 and a final decision from the MPSC is expected in July 2010.

2009 Fuel Cost Decrease Filing:

Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity to its retail customers in Wisconsin. In April 2009, based on three months of actual fuel cost data and nine months of projected data, Wisconsin Electric forecasted that its 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, Wisconsin Electric 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, Wisconsin Electric and Wisconsin Gas initiated rate proceedings. Wisconsin Electric asked the PSCW to approve a comprehensive plan which would result in price increases of $648.6 million for its 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, Wisconsin Electric requested a 1.8% price increase in 2008 for its gas customers and an approximately 16.0% price increase in 2008 for all steam customers in metropolitan Milwaukee. Wisconsin Gas filed for a 4.1% price increase in 2008 for its gas customers. Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with our 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 Wisconsin Electric and Wisconsin Gas as follows

:

- $389.1 million (17.2%) in electric rates for Wisconsin Electric - 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 from Wisconsin Electric;
- $3.6 million (11.2%) for steam service from Wisconsin Electric; and
- $20.1 million (2.2%) for natural gas service from Wisconsin Gas.

In addition, the PSCW lowered the return on equity for Wisconsin Electric and Wisconsin Gas 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.

Wisconsin Electric expects to provide a total of approximately $710.0 million of bill credits to its Wisconsin customers over the three year period ending December 31, 2010. As of September 30, 2009, we have issued approximately $462.4 million of bill credits to Wisconsin retail customers.

2008 Michigan Price Increase

: In January 2008, Wisconsin Electric filed a rate increase request with the MPSC. This request represented an increase in electric rates of 14.7%, or $22.0 million, to support the growing demand for electricity at that time, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational

expenses. In November 2008, a settlement agreement with the MPSC staff and intervenors for a rate increase of $7.2 million, or 4.6%, was approved by the MPSC, effective January 1, 2009.

2008 Fuel Recovery Request:

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

Oak Creek Air Quality Control System Approval:

In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008, and we expect the installation to be completed during 2012. We currently expect the cost of completing this project to be approximately $800 million ($960 million including AFUDC). The amount of AFUDC is based on the assumption that 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 has been included in our previous 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 $55 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 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 -- Utility Rates and Regulatory Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

Renewable Energy Portfolio

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 turbine selection and the final site configuration. We expect 2012 to be the first full year of operation, subject to regulatory approvals.

In addition, in September 2009, we announced plans to construct a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood, waste and sawdust will be used to produce approximately 50 MW of electricity and will also support Domtar's sustainable papermaking operations. We believe the biomass plant will be eligible for either the federal production tax credit or the federal

30% investment tax credit.We currently expect the plant to cost approximately $250 million and to be completed during the first half of 2013, subject to regulatory approvals.

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 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 $7.8 million to us. Several entities filed formal complaints with FERC on the assessment of these charges. We filed in support of these complaints.

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

In addition, FERC ruled on the formal complaints filed by other entities in August 2007. FERC ruled that the current RSG cost allocation methodology may be unjust and unreasonable and established a refund effective date of August 10, 2007. MISO was ordered to file a new cost allocation methodology by March 2008. MISO filed new tariff language which indicated the new cost allocation methodology cannot be applied retroactively. We extended our previous rehearing/clarification request to include the timeframe from the established refund date through

March 2008. In September 2008, FERC set a paper hearing for the formal complaints filed in 2007. FERC ruled on the outstanding rehearing/clarification requests and formal complaints in November 2008. FERC's ruling ordered the resettlements to begin from the date the MISO Energy Markets commenced in order to correct the RSG cost allocation methodology. Additionally, the order also set a new RSG cost allocation effective August 10, 2007. However, numerous entities filed rehearing requests in objection of these rulings. Although MISO requested a postponement of the resettlements until the matter is resolved, the resettlement commenced in March 2009.

In May 2009, FERC issued an order denying rehearing on substantive matters for the rate period beginning August 10, 2007. However, FERC modified the effective date of that rate to November 10, 2008, and ordered MISO to cease the ongoing resettlement and to reconcile all invoices and payments therein. Similarly, in June 2009, FERC dismissed rehearing requests, but waived refunds for the period April 25, 2006 through November 4, 2007. FERC also stated for the first time that it was waiving refunds for the period April 1, 2005 through April 24, 2006. We, along with others, have sought rehearing and/or appeal of the FERC's May and June 2009 determinations pertaining to refunds. In addition, there are contested compliance matters pending FERC review. The net effects of FERC's rulings are uncertain at this time.

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2009 through May 31, 2010. The resulting ARR valuation and the secured FTRs should adequately mitigate our transmission congestion risk for that period.

LEGAL MATTERS

Cash Balance Pension Plan:

On June 30, 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff is attempting to seek class certification for other similarly situated plaintiffs. The complaint alleges that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of 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 our 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 their submittals.

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. In addition, in September 2009, the EPA announced that it would reconsider the 2008 ozone standard to ensure that the standard is protective enough. The EPA has said that it will propose any revisions to the ozone standards by December 2009 and issue a final decision by August 2010.

$PM_{2.5}$

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. In October 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the 2006 daily standard for $PM_{2.5}$. Wisconsin will now have three years to develop a SIP and submit it to the EPA for approval, and will need to implement actions to reach attainment in the 2014-2019 time period. Until such time as the EPA revises the 2006 standard consistent with the court's decision and the states develop rules and submit SIPs to the EPA to demonstrate how they intend to comply with 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 our new PTF generating units being leased by

Wisconsin Electric 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 reconsideration. 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. In July 2009, the EPA issued a proposed information collection request for national emission standards for coal-fired electric generating units. The scope of this request was expanded well beyond mercury and includes other hazardous air pollutants. If finalized, we expect we will be required to complete a detailed survey and extensive testing. The EPA intends to use this data to proceed with developing mercury Maximum Achievable Control Technology limits for utilities.

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, SO_2 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.

Both Wisconsin and Michigan BART rules are based, in part, on utility reductions of NO_x and SO_2 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 Wisconsin Electric's 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:

Federal and state legislative proposals have been introduced to regulate the emission of greenhouse gases, particularly CO_2, 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. On September 30, 2009, Senators John Kerry and Barbara Boxer introduced the Clean Energy Jobs and American Power Act, which contains provisions similar to those in the Waxman-Markey Bill. The provisions of this bill are expected to be debated in the coming months in the U.S. Senate.

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 CO_2 and other greenhouse gases". The group charged with developing a regional cap-and-trade system 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 the U.S. 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.

In addition, a recent decision in the U.S. Court of Appeals for the Second Circuit (*Connecticut v. American Electric Power Co.,* No. 05-5104 (2d Cir., Sept. 21 2009)) has made it easier for lawsuits based upon the alleged public nuisance of climate change to move forward. The court ruled that the plaintiffs have standing to file suit against six electric power corporations for their contribution to the alleged public nuisance of climate change, and that the court's jurisdiction over such lawsuit is not barred by the political question doctrine. The U.S. Court of Appeals for the Fifth Circuit, in another recent decision (*Comer v. Murphy Oil Co.,* No. 07-60756 (5^{th} Cir., Oct. 16, 2009)), made a similar ruling.

EPA Proposals to Regulate Greenhouse Gas Emissions:

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. 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. In September 2009, the EPA proposed a rule that, in concert with its proposed endangerment finding, would result in the regulation of greenhouse gas emissions from motor vehicles.

On September 30, 2009, the EPA issued two proposals intended to provide guidance on, and effectively change, how the CAA's existing permitting requirements could be applied to sources of greenhouse gas emissions in all sectors of the economy, including major stationary sources of air pollutants like electric generating plants. These proposals, if adopted, would provide a framework for EPA to regulate greenhouse gas emissions from major sources under the CAA.

Under the first proposal, the EPA seeks to reconsider a 2008 EPA interpretation of when a pollutant, like CO_2, becomes "subject to regulation" under the CAA's prevention of significant deterioration/new source review permitting program.

The second proposal would revise the threshold for when certain air permit and new source review requirements apply. This proposal is intended to exclude from regulation relatively small sources of greenhouse gas emissions once the EPA issues its final rule regulating emissions from motor vehicles. However, under this proposal, if we wanted to make major changes to a power plant that increases greenhouse gas emissions above certain specified levels, we would be required to obtain a permit that included requirements to minimize greenhouse gas emissions.

Depending on the extent of rate recovery and other factors, adoption of these rules could have a material adverse impact on our operations and financial condition.

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 Energy Corporation, 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.

ITEM 4. 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, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material adverse effect on our financial statements.

UTILITY RATES AND REGULATORY MATTERS

See Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where Wisconsin Electric, Wisconsin Gas and Edison Sault 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 our cash balance pension plan.

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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three-month period ended September 30, 2009:

2009	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(Millions of Dollars)
July 1- July 31	964	$41.27	-	$ -
August 1- August 31	-	-	-	$ -
September 1- September 30	-	$ -	-	$ -
Total	964	$41.27	-	$ -

(a) All shares reported during the quarter were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

ITEM 6. EXHIBITS

Exhibit No.

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.
101	Interactive Data File

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 ENERGY CORPORATION
(Registrant)

/s/STEPHEN P. DICKSON

Date: October 30, 2009

Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer