WISCONSIN ENERGY CORP
Form 10-Q
May 07, 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

## March 31, 2009

| Commission<br>File Number | Registrant; State of Incorporation<br>Address; and Telephone Number | IRS Employer<br>Identification No. |
|---|---|---|
| 001-09057 | WISCONSIN ENERGY CORPORATION<br>(A Wisconsin Corporation)<br>231 West Michigan Street<br>P.O. Box 1331<br>Milwaukee, WI 53201<br>(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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes[ ] No[ ]

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

Large accelerated filer [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 (March 31, 2009):

Common Stock, $.01 Par Value,    116,914,008 shares outstanding.

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WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED MARCH 31, 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

| | |
|---|---|
| <u>Primary Subsidiaries</u> | |
| Edison Sault | Edison Sault Electric Company |
| We Power | W.E. Power, LLC |
| Wisconsin Electric | Wisconsin Electric Power Company |
| Wisconsin Gas | Wisconsin Gas LLC |
| <u>Significant Assets</u> | |
| 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 |
| <u>Other Affiliates</u> | |
| ERS | Elm Road Services, LLC |
| Minergy | Minergy LLC |
| Wispark | Wispark LLC |
| <u>Federal and State Regulatory Agencies</u> | |
| EPA | United States Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| IRS | Internal Revenue Service |
| MPSC | Michigan Public Service Commission |
| PSCW | Public Service Commission of Wisconsin |
| SEC | Securities and Exchange Commission |
| <u>Environmental Terms</u> | |
| 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

| | |
|---|---|
| ALJ | Wisconsin Administrative Law Judge |
| ARRs | Auction Revenue Rights |



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.

- 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 performance of projects undertaken by our non-utility businesses.

- 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, We Power and Edison Sault.

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 March 31 | |
|---|---|---|
| | 2009 | 2008 |
| Operating Revenues | $1,396.2 | $1,431.1 |
| Operating Expenses | | |
| Fuel and purchased power | 266.4 | 338.2 |
| Cost of gas sold | 502.7 | 560.2 |
| Other operation and maintenance | 334.4 | 369.4 |
| Depreciation, decommissioning and amortization | 85.8 | 77.7 |
| Property and revenue taxes | 28.1 | 27.1 |
| Total Operating Expenses | 1,217.4 | 1,372.6 |
| Amortization of Gain | 64.2 | 159.0 |
| Operating Income | 243.0 | 217.5 |
| Equity in Earnings of Transmission Affiliate | 14.3 | 11.5 |
| Other Income, net | 6.3 | 10.6 |
| Interest Expense, net | 40.8 | 39.2 |
| Income from Continuing Operations Before Income Taxes | 222.8 | 200.4 |
| Income Taxes | 81.3 | 77.4 |
| Income from Continuing Operations | 141.5 | 123.0 |
| Income from Discontinued | | |

| | | |
|---|---|---|
| Operations, Net of Tax | - | 0.2 |
| Net Income | $141.5 | $123.2 |
| | | |
| Earnings Per Share (Basic) | | |
| Continuing operations | $1.21 | $1.05 |
| Discontinued operations | - | - |
| Total Earnings Per Share (Basic) | $1.21 | $1.05 |
| | | |
| Earnings Per Share (Diluted) | | |
| Continuing operations | $1.20 | $1.04 |
| Discontinued operations | - | - |
| Total Earnings Per Share (Diluted) | $1.20 | $1.04 |
| | | |
| Weighted Average Common Shares Outstanding (Millions) | | |
| Basic | 116.9 | 116.9 |
| Diluted | 118.0 | 118.3 |
| | | |
| Dividends Per Share of Common Stock | $0.3375 | $0.27 |

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



WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED BALANCE SHEETS

| | (Unaudited) March 31, 2009 | December 31, 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Assets | | |
| Property, Plant and Equipment | | |
| In service | $ 10,088.6 | $ 9,909.4 |

| | | |
|---|---|---|
| Accumulated depreciation | (3,370.4) | (3,312.9) |
| | 6,718.2 | 6,596.5 |
| Construction work in progress | 1,807.4 | 1,829.9 |
| Leased facilities, net | 74.8 | 76.2 |
| Net Property, Plant and Equipment | 8,600.4 | 8,502.6 |
| Investments | | |
| Restricted cash | 145.0 | 172.4 |
| Equity investment in transmission affiliate | 285.5 | 276.3 |
| Other | 39.0 | 41.6 |
| Total Investments | 469.5 | 490.3 |
| Current Assets | | |
| Cash and cash equivalents | 17.1 | 32.5 |
| Restricted cash | 183.6 | 214.1 |
| Accounts receivable | 527.6 | 369.5 |
| Accrued revenues | 223.1 | 341.2 |
| Materials, supplies and inventories | 251.3 | 344.7 |
| Regulatory assets | 98.6 | 82.5 |
| Prepayments and other | 231.5 | 323.0 |
| Total Current Assets | 1,532.8 | 1,707.5 |
| Deferred Charges and Other Assets | | |
| Regulatory assets | 1,211.8 | 1,261.1 |
| Goodwill | 441.9 | 441.9 |
| Other | 154.7 | 214.4 |
| Total Deferred Charges and Other Assets | 1,808.4 | 1,917.4 |
| Total Assets | $ 12,411.1 | $ 12,617.8 |
| Capitalization and Liabilities | | |
| Capitalization | | |
| Common equity | $ 3,439.6 | $ 3,336.9 |
| Preferred stock of subsidiary | 30.4 | 30.4 |
| Long-term debt | 4,083.4 | 4,074.7 |
| Total Capitalization | 7,553.4 | 7,442.0 |
| Current Liabilities | | |
| Long-term debt due currently | 12.3 | 61.8 |
| Short-term debt | 791.3 | 602.3 |
| Accounts payable | 303.9 | 441.0 |
| Regulatory liabilities | 263.1 | 310.8 |
| Other | 335.2 | 319.2 |

| | | |
|---|---|---|
| Total Current Liabilities | 1,705.8 | 1,735.1 |
| Deferred Credits and Other Liabilities | | |
| Regulatory liabilities | 1,062.7 | 1,084.4 |
| Deferred income taxes - long-term | 829.4 | 814.0 |
| Deferred revenue, net | 592.2 | 545.4 |
| Pension and other benefit obligations | 317.8 | 635.0 |
| Other | 349.8 | 361.9 |
| Total Deferred Credits and Other Liabilities | 3,151.9 | 3,440.7 |
| Total Capitalization and Liabilities | $ 12,411.1 | $ 12,617.8 |

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

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WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS

(Unaudited)

| | Three Months Ended March 31 | |
|---|---|---|
| | 2009 | 2008 |
| | (Millions of Dollars) | |
| Operating Activities | | |
| Net income | $ 141.5 | $ 123.2 |
| Reconciliation to cash | | |
| Depreciation, decommissioning and amortization | 87.6 | 82.4 |
| Amortization of gain | (64.2) | (159.0) |
| Equity in earnings of transmission affiliate | (14.3) | (11.5) |
| Distributions from transmission affiliate | 11.4 | 8.3 |
| Deferred income taxes and investment tax credits, net | (2.8) | (9.9) |
| Deferred revenue | 48.6 | 50.9 |
| Contributions to benefit plans | (289.3) | (48.4) |
| Change in - | (40.0) | (106.8) |

| | | |
|---|---|---|
| Accounts receivable and accrued revenues | | |
| Inventories | 93.4 | 126.2 |
| Other current assets | 14.7 | 18.7 |
| Accounts payable | (119.5) | 5.8 |
| Accrued income taxes, net | 82.0 | 85.7 |
| Deferred costs, net | 11.5 | 44.6 |
| Other current liabilities | 16.2 | 44.1 |
| Other, net | 43.5 | 89.5 |
| Cash Provided by Operating Activities | 20.3 | 343.8 |
| Investing Activities | | |
| Capital expenditures | (171.4) | (348.2) |
| Investment in transmission affiliate | (6.3) | - |
| Proceeds from asset sales, net | 0.1 | 9.1 |
| Change in restricted cash | 57.9 | 88.3 |
| Other, net | (23.3) | (20.1) |
| Cash Used in Investing Activities | (143.0) | (270.9) |
| Financing Activities | | |
| Exercise of stock options | 3.0 | 2.7 |
| Purchase of common stock | (5.6) | (5.5) |
| Dividends paid on common stock | (39.5) | (31.6) |
| Issuance of long-term debt | 11.5 | - |
| Retirement and repurchase of long-term debt | (51.7) | (148.0) |
| Change in short-term debt | 189.0 | 105.7 |
| Other, net | 0.6 | 0.6 |
| Cash Provided by (Used in) Financing Activities | 107.3 | (76.1) |
| Change in Cash and Cash Equivalents | (15.4) | (3.2) |
| Cash and Cash Equivalents at Beginning of Period | 32.5 | 27.4 |
| Cash and Cash Equivalents at End of Period | $ 17.1 | $ 24.2 |

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 to a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three months ended March 31, 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 most significant reclassifications relate to the reporting of discontinued operations pursuant to SFAS 144. The footnotes contained herein reflect continuing operations for all periods presented. For further information, see Note 5.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements:

In September 2006, the FASB issued SFAS 157. SFAS 157 defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value, and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We partially adopted the provisions of SFAS 157 effective January 1, 2008. We fully adopted the provisions of SFAS 157 effective January 1, 2009. The adoption of SFAS 157 did not have a significant financial impact on our consolidated financial statements. See Note 6 -- Fair Value Measurements for required disclosures.

Noncontrolling Interests in Consolidated Financial Statements:

In December 2008, the FASB issued SFAS 160. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. We adopted the provisions of SFAS 160 effective January 1, 2009. The adoption of SFAS 160 did not have a material financial impact on our consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities:

In March 2008, the FASB issued SFAS 161, which amends SFAS 133. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 is effective for fiscal years beginning after November 15, 2008. We adopted the provisions of SFAS 161 effective January 1, 2009. The adoption of SFAS 161 did not have any financial impact on our consolidated financial statements. See Note 7 -- Derivative Instruments for required disclosures.



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 in 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 three months ended March 31, 2009 and approximately 6% in 2008. Capitalized interest is included in the total cost of the PTF units.

Cash Flows:

The following table identifies key pre-tax cash outflows and inflows for the three months ended March 31 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 | $ - | $ - | $17.6 | $22.4 | $40.0 | $171.4 |
| 2008 | $ - | $22.6 | $70.3 | $81.9 | $174.8 | $348.2 |

| | Capitalized Interest (Millions of Dollars) | | | | Total | |
|---|---|---|---|---|---|---|
| | PWGS 1 | PWGS 2 | OC 1 | OC 2 | PTF | WEC |
| 2009 | $ - | $ - | $11.2 | $6.8 | $18.0 | $19.2 |
| 2008 | $ - | $4.5 | $11.4 | $5.2 | $21.1 | $22.2 |

| | Deferred Revenue (Millions of Dollars) | | | | Total | |
|---|---|---|---|---|---|---|
| | PWGS 1 | PWGS 2 | OC 1 | OC 2 | PTF | WEC |
| 2009 | $ - | $ - | $30.4 | $18.2 | $48.6 | $48.6 |
| 2008 | $ - | $10.6 | $27.5 | $12.8 | $50.9 | $50.9 |

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 Other 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 March 31, 2009 and December 31, 2008:



| | CWIP - Cash Expenditures (Millions of Dollars) | | | | Total |
|---|---|---|---|---|---|
| | PWGS 1 | PWGS 2 | OC 1 | OC 2 | PTF |
| March 31, 2009 | $ - | $ - | $850.6 | $530.7 | $1,381.3 |
| 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 |
| March 31, 2009 | $ - | $ - | $957.6 | $588.0 | $1,545.6 | $1,807.4 |
| 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 |
| March 31, 2009 | $330.2 | $357.6 | $324.7 | $ - | $1,012.5 | $6,718.2 |
| | $332.7 | $360.3 | $194.0 | $ - | $887.0 | $6,596.5 |

December 31,
2008

| | Deferred Revenue (Millions of Dollars) | | | | Total | |
|---|---|---|---|---|---|---|
| | PWGS 1 | PWGS 2 | OC 1 | OC 2 | PTF | WEC |
| March 31, 2009 | $61.9 | $76.5 | $315.6 | $138.2 | $592.2 | $592.2 |
| 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 on a straight line basis 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 under SFAS 123R. 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 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 for the three months ended March 31:

| | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Stock options | $2.5 | $ 3.0 |
| Performance units | 3.8 | 1.2 |
| Restricted stock | 0.2 | 0.3 |
| Share-based compensation expense | $6.5 | $4.5 |
| Related tax benefit | $2.6 | $1.8 |

Stock Option Activity:

During the first three 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 three months of 2008, the Compensation Committee granted 1,362,160 options which have 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 through the three months ended March 31, 2009:

| Stock Options | Number of Options | Weighted-Average Exercise Price | Weighted-Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value (Millions) |
|---|---|---|---|---|
| Outstanding as of January 1, 2009 | 8,543,564 | $36.97 | | |
| Granted | 1,216,625 | $42.22 | | |
| Exercised | (126,520) | $23.64 | | |
| Forfeited | - | $ - | | |
| Outstanding as of March 31, 2009 | 9,633,669 | $37.81 | 6.5 | $52.0 |
| Exercisable as of March 31, 2009 | 5,909,814 | $32.63 | 5.0 | $52.0 |

The intrinsic value of options exercised was $2.5 million and $2.1 million for the three months ended March 31, 2009 and 2008, respectively. Cash received from options exercised was $3.0 million and $2.7 million for the three months ended March 31, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $1.0 million and $0.7 million, respectively.

Stock options to purchase 12,000, 1,366,625, 1,357,365 and 1,216,625 shares of common stock at $42.56, $47.76, $48.04 and $42.22 per share, respectively, were outstanding during the first quarter 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 our stock options outstanding as of March 31, 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 | 1,973,070 | $25.19 | 3.4 | 1,973,070 | $25.19 | 3.4 |
| $33.44 to $39.48 | 3,707,984 | $35.65 | 5.7 | 3,707,984 | $35.65 | 5.7 |
| $42.22 to $48.04 | 3,952,615 | $46.13 | 8.7 | 228,760 | $47.79 | 7.9 |
| | 9,633,669 | $37.81 | 6.5 | 5,909,814 | $32.63 | 5.0 |

The following table summarizes information about our non-vested options during the three months ended March 31, 2009:

| Non-Vested Stock Options | Number of Options | Weighted-Average Fair Value |
|---|---|---|
| Non-vested as of January 1, 2009 | 3,598,379 | $8.81 |
| Granted | 1,216,625 | $8.01 |
| Vested | (1,091,149) | $7.55 |
| Forfeited | - | $ - |
| Non-vested as of March 31, 2009 | 3,723,855 | $8.72 |

As of March 31, 2009, total compensation costs related to non-vested stock options not yet recognized was approximately $15.7 million, which is expected to be recognized over the next 21 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 months ended March 31, 2009:

| Restricted Shares | Number of Shares | Weighted-Average Grant Date Fair Value |
|---|---|---|
| Outstanding as of January 1, 2009 | 116,373 | |
| Granted | 14,216 | $42.11 |
| Released / Forfeited | (13,079) | $38.95 |
| Outstanding as of March 31, 2009 | 117,510 | |

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 $0.6 million for the three months ended March 31, 2009. The intrinsic value for the same period in 2008 was $1.0 million. The actual tax benefit realized for the tax deductions from released restricted shares was $0.2 million for the three months ended March 31, 2009 and

$0.1 million for the same period in 2008.

As of March 31, 2009, total compensation cost related to restricted stock not yet recognized was approximately $2.0 million, which is expected to be recognized over the next 34 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 the 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 March 31, 2009, total compensation cost related to performance units not yet recognized was approximately $20 million, which is expected to be recognized over the next 27 months on a weighted-average basis.

Restrictions:

Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. 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 during the three months ended March 31:

| Comprehensive Income | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Net Income | $141.5 | $123.2 |
| Other Comprehensive Income | | |
| Hedging | 0.1 | 0.1 |

| | | |
|---|---|---|
| Total Other Comprehensive Income | 0.1 | 0.1 |
| Total Comprehensive Income | $141.6 | $123.3 |

5 -- DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

Sale of Water Business

**:** We previously announced that we had reached an agreement to sell the water utility to the City of Mequon, Wisconsin for approximately $14.5 million. The completion of the sale was contingent upon certain conditions, including the assignment of certain agreements, approval by the PSCW and the ability of the City of Mequon to obtain financing. In March 2009, we received approval by the PSCW and have classified these assets as held for sale in accordance with SFAS 144. In April 2009 the sale was completed.



Assets and liabilities held for sale are recorded in other current assets and liabilities on our Consolidated Condensed Balance Sheets follow:

| | March 31, 2009 | December 31, 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Assets: | | |
| Property, plant and equipment, net | $14.4 | $14.4 |
| Total assets of discontinued operations | $14.4 | $14.4 |
| Liabilities: | | |
| Deferred Credits and Other Liabilities | $0.3 | $0.3 |
| Total liabilities of discontinued operations | $0.3 | $0.3 |

A summary of the components of Income from Discontinued Operations, Net of Tax in our Consolidated Condensed Income Statements for the three months ended March 31 follows:

| | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Operating revenues | $0.7 | $0.7 |
| Operating expenses | 0.3 | 0.3 |

| | | |
|---|---|---|
| Income before income taxes | 0.4 | 0.4 |
| Income tax expense | 0.2 | 0.2 |
| Income from discontinued water operations, net of tax | 0.2 | 0.2 |
| Income (Loss) from discontinued other operations, net of tax | (0.2) | - |
| Total Income from Discontinued Operations, Net of Tax | $ - | $0.2 |

Cash provided by operating activities in our Consolidated Condensed Statements of Cash Flows reflects Income from discontinued operations, net of tax of zero and $0.2 million for the three months ended March 31, 2009 and 2008, respectively. Discontinued water operations had no impact on Cash used in investing activities or financing activities for the three months ended March 31, 2009 and March 31, 2008.

6 -- FAIR VALUE MEASUREMENTS

We adopted SFAS 157 as of January 1, 2008, which among other things, requires enhanced disclosures about assets and liabilities that are measured and reported at fair value. SFAS 157 establishes a hierarchal disclosure framework which prioritizes and ranks the level of observable inputs used in measuring fair value.

As defined in SFAS 157, 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 established under SFAS 157 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 SFAS 157 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 March 31, 2009 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| | (Millions of Dollars) | | | |
| Assets: | | | | |
| Restricted Cash | $328.6 | $ - | $ - | $328.6 |
| Derivatives | - | 4.3 | 2.9 | 7.2 |
| Total | $328.6 | $4.3 | $2.9 | $335.8 |
| Liabilities: | | | | |
| Derivatives | $48.9 | $9.1 | $ - | $58.0 |
| Total | $48.9 | $9.1 | $ - | $58.0 |

| 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.

| Fair Value of Derivatives | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Balance as of January 1 | $8.8 | $13.0 |
| Realized and unrealized gains (losses) | - | - |
| Settlements | (5.9) | (8.5) |
| Transfers in and/or out of Level 3 | - | - |
| Balance as of March 31 | $2.9 | $4.5 |
| Change in unrealized gains (losses) relating to instruments still held as of March 31 | $ - | $ - |

Derivative instruments reflected in Level 3 of the hierarchy include FTRs allocated by MISO 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 in



accordance with SFAS 71. See Note 7 -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

7 -- DERIVATIVE INSTRUMENTS

We follow SFAS 133, as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be 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 under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities in accordance with SFAS 71. 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 March 31, 2009, we recognized $76.0 million in regulatory assets and $7.2 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 derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative liability is recorded in Other deferred liabilities. Our Consolidated Condensed Balance Sheet as of March 31, 2009 includes:

| | Derivative Asset | Derivative Liability |
|---|---|---|
| | (Millions of Dollars) | |
| Natural Gas | $0.1 | $54.3 |
| Energy | - | 0.3 |
| Fuel Oil | - | 1.7 |
| FTRs | 2.9 | - |
| Coal | 4.2 | 1.7 |
| Total | $7.2 | $58.0 |

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under Fuel and purchased power for those commodities supporting our electric operations and under Cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gain (losses) for the quarter ended March 31, 2009 follow:

| | Volumes | Gains (Losses) |
|---|---|---|
| | | (Millions of Dollars) |
| Natural Gas | 22.4 million Dth | ($24.9) |
| Energy | 11,920 MWh purchased | (0.5) |
| Fuel Oil | 1.26 million gallons | (0.9) |
| FTRs | 6,354 MW | (4.9) |
| Coal | 110,000 tons | (0.5) |
| Total | | ($31.7) |

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of March 31, 2009, is $58.0 million for which we have posted collateral of $67.0 million in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered, we would be covered by the collateral in our margin accounts.

8 -- BENEFITS

The components of our net periodic pension and OPEB costs for the three months ended March 31 were as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| Benefit Plan Cost Components | 2009 | 2008 | 2009 | 2008 |
| | (Millions of Dollars) | | | |
| Net Periodic Benefit Cost | | | | |
| Service cost | $5.3 | $4.7 | $2.3 | $2.7 |
| Interest cost | 18.2 | 17.3 | 5.3 | 5.2 |
| Expected return on plan assets | (23.7) | (21.4) | (3.5) | (4.4) |
| Amortization of: | | | | |
| Transition obligation | - | - | 0.1 | 0.1 |
| Prior service cost (credit) | 0.6 | 0.6 | (3.2) | (3.1) |
| Actuarial loss | 5.2 | 3.7 | 2.3 | 1.7 |
| Net Periodic Benefit Cost | $5.6 | $4.9 | $3.3 | $2.2 |

As of December 31, 2008, the returns on our pension plan assets and OPEB plans were significantly below our expected rate of return of 8.5%. 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 Plan Trustee to invest in the commercial paper of Wisconsin Energy. As of March 31, 2009, the Pension Trust held approximately $90 million of commercial paper issued by Wisconsin Energy.

9 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of March 31, 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, excluding severance benefits, for such benefits was $19.4 million as of March 31, 2009 and $18.6 million as of December 31, 2008.



**10 -- SEGMENT INFORMATION**

Summarized financial information concerning our reportable operating segments for the three month periods ended March 31, 2009 and 2008 is shown in the following table:

| | Reportable Operating Segments | | Corporate & Other (a) & Reconciling | Total |
|---|---|---|---|---|
| | Energy | | | |
| Wisconsin Energy Corporation | Utility | Non-Utility | Items | Consolidated |

| | (Millions of Dollars) | | | |
|---|---|---|---|---|
| Three Months Ended | | | | |
| March 31, 2009 | | | | |
| Operating Revenues (b) | $1,395.6 | $36.7 | ($36.1) | $1,396.2 |
| Depreciation, Decommissioning and Amortization | $78.5 | $7.2 | $0.1 | $85.8 |
| Operating Income (Loss) | $216.3 | $27.9 | ($1.2) | $243.0 |
| Equity in Earnings of Unconsolidated Affiliates | $14.3 | $ - | ($0.1) | $14.2 |
| Interest Expense, net | $30.1 | $4.1 | $6.6 | $40.8 |
| Income Tax Expense (Benefit) | $73.4 | $10.8 | ($2.9) | $81.3 |
| Income (Loss) from Discontinued Operations, Net of Tax | $0.2 | $ - | ($0.2) | $ - |
| Net Income (Loss) | $133.4 | $13.9 | ($5.8) | $141.5 |
| Capital Expenditures | $130.2 | $41.2 | $ - | $171.4 |
| Total Assets (c) | $10,757.2 | $2,536.7 | ($882.8) | $12,411.1 |
| March 31, 2008 | | | | |
| Operating Revenues (b) | $1,432.5 | $19.7 | ($21.1) | $1,431.1 |
| Depreciation, Decommissioning and Amortization | $73.5 | $3.9 | $0.3 | $77.7 |
| Operating Income (Loss) | $206.3 | $14.2 | ($3.0) | $217.5 |
| Equity in Earnings of Unconsolidated Affiliates | $11.5 | $ - | ($0.1) | $11.4 |
| Interest Expense, net | $28.3 | $1.8 | $9.1 | $39.2 |
| Income Tax Expense (Benefit) | $77.2 | $5.0 | ($4.8) | $77.4 |
| Income from Discontinued Operations,Net of Tax | $0.2 | $ - | $ - | $0.2 |
| Net Income (Loss) | $121.5 | $7.4 | ($5.7) | $123.2 |
| Capital Expenditures | $173.0 | $175.2 | $ - | $348.2 |
| Total Assets (c) | $10,018.6 | $2,160.9 | ($501.4) | $11,678.1 |

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

(b) An elimination for intersegment revenues of $36.0 million and $19.8 million is included in Operating Revenues for the three months ended March 31, 2009 and 2008, respectively. This elimination is primarily between We Power and Wisconsin Electric.

(c) Includes an elimination of $900.7 million and $460.8 million as of March 31, 2009 and March 31, 2008, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

## 11 -- VARIABLE INTEREST ENTITIES

Under FIN 46 and FIN 46R, the primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. In December 2008, the FASB issued FSP FIN 46(R)-8 requiring additional disclosures 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 as prescribed by FIN 46(R). 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 as defined by FIN 46(R). 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 $459.8 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 March 31, 2009 and December 31, 2008, were $14.1 million and $66.4 million, respectively.

## 12 -- 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.

13 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the three months ended March 31, 2009, we paid $14.4 million in interest, capitalized $19.2 million of interest expense and paid $0.8 million in income taxes, net of refunds. During the three months ended March 31, 2008, we paid $4.5 million in interest, net of amounts capitalized, and $0.1 million in income taxes, net of refunds.

As of March 31, 2009 and 2008, the amount of accounts payable related to capital expenditures was $27.5 million and $70.7 million, respectively.



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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED MARCH 31, 2009

CONSOLIDATED EARNINGS

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

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2009 | B (W) | 2008 |
| | (Millions of Dollars) | | |
| Utility Energy Segment | $216.3 | $10.0 | $206.3 |
| Non-Utility Energy Segment | 27.9 | 13.7 | 14.2 |
| Corporate and Other | (1.2) | 1.8 | (3.0) |
| Total Operating Income | 243.0 | 25.5 | 217.5 |
| Equity in Earnings of Transmission Affiliate | 14.3 | 2.8 | 11.5 |
| Other Income, net | 6.3 | (4.3) | 10.6 |
| Interest Expense, net | 40.8 | (1.6) | 39.2 |
| Income From Continuing Operations Before Income Taxes | 222.8 | 22.4 | 200.4 |
| Income Taxes | 81.3 | (3.9) | 77.4 |

| | | | |
|---|---|---|---|
| Income From Continuing Operations | 141.5 | 18.5 | 123.0 |
| Income From Discontinued Operations, Net of Tax | - | (0.2) | 0.2 |
| Net Income | $141.5 | $18.3 | $123.2 |
| Diluted Earnings Per Share | $1.20 | $0.16 | $1.04 |

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UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $216.3 million of operating income during the first quarter of 2009, an increase of $10.0 million, or 4.8%, compared with the first quarter of 2008. The following table summarizes the operating income of this segment between the comparative quarters:

| | Three Months Ended March 31 | | |
|---|---|---|---|
| Utility Energy Segment | 2009 | B (W) | 2008 |
| | | (Millions of Dollars) | |
| Operating Revenues | | | |
| Electric | $693.5 | $26.3 | $667.2 |
| Gas | 686.9 | (63.0) | 749.9 |
| Other | 15.2 | (0.2) | 15.4 |
| Total Operating Revenues | 1,395.6 | (36.9) | 1,432.5 |
| Fuel and Purchased Power | 267.6 | 71.6 | 339.2 |
| Cost of Gas Sold | 502.7 | 57.5 | 560.2 |
| Gross Margin | 625.3 | 92.2 | 533.1 |
| Other Operating Expenses | | | |
| Other Operation and Maintenance | 366.7 | 18.6 | 385.3 |
| Depreciation, Decommissioning and Amortization | 78.5 | (5.0) | 73.5 |
| Property and Revenue Taxes | 28.0 | (1.0) | 27.0 |
| Total Operating Expenses | 1,243.5 | 141.7 | 1,385.2 |
| Amortization of Gain | 64.2 | (94.8) | 159.0 |
| Operating Income | $216.3 | $10.0 | $206.3 |

The increase in Operating Income for the three months ended March 31, 2009 as compared to the same period in 2008 was primarily caused by favorable recoveries of revenues associated with fuel and purchased power. During the first quarter of 2009, we experienced favorable fuel recoveries of approximately $28 million. During the same period in 2008, we experienced unfavorable fuel recoveries of approximately $14 million. While we experienced a net $42 million positive increase in fuel recoveries in the first quarter 2009 as compared to the same period in 2008, we expect a substantial portion of the favorable fuel recoveries to reverse by the end of the year as a result of a request we filed with the PSCW to reduce Wisconsin retail electric rates for calendar year 2009. For additional information on the rate filing, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

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



Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the three months ended March 31:

| | Electric Revenues | | | MWh Sales | | |
|---|---|---|---|---|---|---|
| Electric Utility Operations | 2009 | B (W) | 2008 | 2009 | B (W) | 2008 |
| | | (Millions of Dollars) | | | (Thousands) | |
| Operating Revenues | | | | | | |
| Residential | $262.9 | $15.4 | $247.5 | 2,132.0 | (76.7) | 2,208.7 |
| Small Commercial/Industrial | 227.7 | 17.0 | 210.7 | 2,279.6 | (53.1) | 2,332.7 |
| Large Commercial/Industrial | 145.1 | (10.8) | 155.9 | 2,239.8 | (485.7) | 2,725.5 |
| Other-Retail | 5.7 | 0.2 | 5.5 | 42.4 | (2.2) | 44.6 |
| Total Retail | 641.4 | 21.8 | 619.6 | 6,693.8 | (617.7) | 7,311.5 |
| Wholesale - Other | 29.6 | (4.1) | 33.7 | 469.3 | (152.5) | 621.8 |
| Resale - Utilities | 17.9 | 12.5 | 5.4 | 477.1 | 280.9 | 196.2 |
| Other Operating Revenues | 4.6 | (3.9) | 8.5 | - | - | - |
| Total | $693.5 | $26.3 | $667.2 | 7,640.2 | (489.3) | 8,129.5 |

| | | | |
|---|---|---|---|
| Weather -- Degree Days (a) | | | |
| Heating (3,240 Normal) | 3,458 | (95) | 3,553 |

(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 $26.3 million, or 3.9%, when compared to the first quarter of 2008. We estimate that our first quarter 2009 revenues were $57.3 million higher than the first quarter of 2008 due to pricing increases that we received during January 2008 as part of the 2008 PSCW rate case that were in effect for a full quarter in 2009, as well as pricing increases related to fuel that we received in a final fuel order from the PSCW in July 2008. For more information on the pricing increases, see Utility Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources below. We also estimate that our electric revenues increased by $9.8 million as a result of fewer bill credits to our customers from the sale of Point Beach during the first quarter of 2009 as compared to the same period in 2008. For more information on bill credits, see Amortization of Gain in Results of Operations. These increases were partially offset by a $10 million decrease in electric revenues related to MISO RSG credits that may be received during 2009. For more information on the MISO RSG credits, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2008 Fuel Recovery Request.

Our total electric sales volumes decreased by approximately 6.0%, with retail sales volumes declining nearly 8.4%. Of the 8.4% decline in retail sales volumes, approximately 7.4% relates to sales volumes at our small and large commercial and industrial customers. The primary reason for the reduced sales volumes relates to a decline in economic conditions during the first quarter of 2009 as compared to the same period in 2008. Additionally, milder weather during the first three months of 2009 as compared to the same period in 2008 reduced revenues by approximately $2.2 million. As measured by heating degree days, the first quarter of 2009 was 2.7% warmer than the first quarter of 2008.

For 2009, we expect to see a continued decline in electric sales to commercial and industrial customers as compared to 2008 as a result of the downturn in the economy. We also expect to see a reduction in revenues because of the April 2009 fuel cost decrease filing, which is expected to reduce annual revenues by $67.2 million. 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 $71.6 million, or 26.8%, when compared to the first quarter of 2008. The largest factor related to this decrease was the one-time amortization of deferred fuel costs of $41.2 million that occurred in January 2008. Adjusted for the one-time amortization, our fuel and purchased power costs decreased by $30.4 million, or 11.4%. This decline was caused by lower MWh sales as well as lower natural gas and purchased power prices, partially offset by higher coal and related transportation costs.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first quarter of 2009 with similar information for the first 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 revenues decreased by $63.0 million, or 8.4%, primarily due to milder weather and lower gas prices.

| | Three Months Ended March 31 | | |
|---|---|---|---|
| Gas Utility Operations | 2009 | B (W) | 2008 |
| | (Millions of Dollars) | | |
| Gas Operating Revenues | $686.9 | ($63.0) | $749.9 |
| Cost of Gas Sold | 502.7 | 57.5 | 560.2 |
| Gross Margin | $184.2 | ($5.5) | $189.7 |

The following table compares our gas utility gross margin and therm deliveries by customer class during the three months ended March 31:

| | Gross Margin | | | Therm Deliveries | | |
|---|---|---|---|---|---|---|
| Gas Utility Operations | 2009 | B (W) | 2008 | 2009 | B (W) | 2008 |
| | (Millions of Dollars) | | | (Millions) | | |
| Customer Class | | | | | | |
| Residential | $118.0 | ($3.6) | $121.6 | 390.0 | (18.8) | 408.8 |
| Commercial/Industrial | 47.4 | (0.9) | 48.3 | 231.3 | (9.1) | 240.4 |
| Interruptible | 0.7 | (0.1) | 0.8 | 7.1 | (1.3) | 8.4 |
| Total Retail | 166.1 | (4.6) | 170.7 | 628.4 | (29.2) | 657.6 |
| Transported Gas | 15.2 | (1.0) | 16.2 | 272.9 | (21.8) | 294.7 |
| Other | 2.9 | 0.1 | 2.8 | - | - | - |
| Total | $184.2 | ($5.5) | $189.7 | 901.3 | (51.0) | 952.3 |
| Weather -- Degree Days (a) | | | | | | |
| Heating (3,240 Normal) | | | | 3,458 | (95) | 3,553 |

(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 $5.5 million, or approximately 2.9%, when compared to the first quarter of 2008. We estimate that approximately $4.1 million of this decrease relates to a decline in sales volumes as a result of milder winter weather during the first quarter of 2009 as compared to the first quarter of 2008. As measured by heating degree days, the first three months of 2009 were 2.7% warmer than the same period in 2008 and 6.7% cooler than normal. Pricing increases that we received during January 2008 as part of the 2008 PSCW rate case that were in effect for a full quarter in 2009 partially offset the negative drivers.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $18.6 million, or approximately 4.8%, when compared to the first quarter of 2008. The largest factor for this decrease relates to a $43.8 million one-time amortization of deferred bad debt costs in connection with the January 2008 PSCW rate order, which we recorded during the first quarter of 2008. The January 2008 PSCW rate order, which was in effect for a full quarter 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 $15.5 million higher in the first quarter of 2009 as compared to the same period in 2008.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by $5.0 million, or approximately 6.8%, when compared to the first quarter of 2008. This increase is the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed in service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached an agreement with our regulators to allow for the net gain on the sale 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 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 March 31:

| Amortization of Gain | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Bill Credits - Retail | $64.2 | $74.0 |
| One-Time Amortization | - | 85.0 |
| Total Amortization of Gain | $64.2 | $159.0 |

For the remainder of 2009, we expect to see a reduction in the Amortization of Gain as compared to 2008 because of the one-time entry identified above and a one-time $62.5 million FERC approved refund to our wholesale customers in 2008, as well as an expected approximately $100 million annual decrease in bill credits to retail customers.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $27.9 million of operating income for the first quarter of 2009 as compared to $14.2 million for the first quarter of 2008. The increase primarily relates to earnings from PWGS 2, which was placed in service in May 2008, and earnings from the new water intake system for Oak Creek that was placed in service in January 2009.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by $4.3 million, or approximately 40.6%, when compared to the first quarter of 2008. This decrease primarily relates to reduced property sales during the first quarter of 2009 as compared to the same period in 2008.

CONSOLIDATED INTEREST EXPENSE, NET

| | Three Months Ended March 31 | |
|---|---|---|
| Interest Expense | 2009 | 2008 |
| | (Millions of Dollars) | |
| Gross Interest Costs | $60.0 | $61.4 |
| Less: Capitalized Interest | 19.2 | 22.2 |
| Interest Expense, Net | $40.8 | $39.2 |

Our gross interest costs decreased by $1.4 million in 2009 primarily due to lower short-term interest rates, which were partially offset by higher debt balances. Our capitalized interest decreased by $3.0 million due to a reduction in CWIP balances during the first three months of 2009 as compared to the same period in 2008. In May 2008, PWGS 2 and the Blue Sky Green Field wind project were completed. Additionally, in January 2009, the water intake system that will serve both the existing units at Oak Creek and OC 1 and OC 2 was placed in service. As a result, our net interest expense increased by $1.6 million, or 4.1%, as compared to the first quarter of 2008.

CONSOLIDATED INCOME TAXES

For the first quarter of 2009, our effective tax rate applicable to continuing operations was 36.5% compared to 38.6% for the first quarter of 2008. We expect our 2009 annual effective tax rate to be between 35% and 37%.

## LIQUIDITY AND CAPITAL RESOURCES

### CASH FLOWS

The following summarizes our cash flows from continuing operations during the three months ended March 31:

| Wisconsin Energy Corporation | 2009 | 2008 |
|---|---|---|
| | (Millions of Dollars) | |
| Cash Provided by (Used in) | | |
| Operating Activities | $20.3 | $343.8 |
| Investing Activities | ($143.0) | ($270.9) |
| Financing Activities | $107.3 | ($76.1) |

Operating Activities

Cash provided by operating activities was $20.3 million during 2009, which was $323.5 million lower than 2008. Although we experienced an increase in net income during the first quarter of 2009, there were two large factors that reduced cash from operations. In the first quarter of 2009, we contributed $289.3 million to our benefit plans as compared to approximately $48.4 million in the first quarter of 2008. The second factor, which reduced cash from operations related to a reduction in our accounts payable as a result of falling natural gas prices.

Investing Activities

Cash used in investing activities was $143.0 million during the three months ended March 31, 2009, which was $127.9 million lower than the same period in 2008. This decline reflects lower capital expenditures during the first quarter of 2009 and positive cash flows from the release of restricted cash.

During the first quarter of 2009, our capital expenditures decreased $176.8 million primarily due to the reduction in the capital expenditures for our Oak Creek expansion and PWGS 2, which was completed in 2008.

During the first quarter of 2009, we released $30.4 million less from restricted cash as compared to the same period in 2008. As background, 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 three months ended March 31, 2009 was $107.3 million, compared to cash used in financing activities during the same period in 2008 of $76.1 million. During the first quarter of 2009, we paid approximately $39.5 million in cash dividends and increased our debt levels by a net amount of approximately $148.8 million.

During the first three months of 2009, we received proceeds of $3.0 million related to the exercise of stock options, compared with $2.7 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 $5.6 million, compared with $5.5 million in the first quarter 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 nine 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.

Despite the continued turmoil in the global credit markets, we still currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable 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 March 31, 2009, we had approximately $1.6 billion of available, undrawn lines under our bank back-up credit facilities. As of March 31, 2009, we had approximately $791.3 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 at March 31, 2009:

| Company | Total Facility * | Letters of Credit | Credit Available * | Facility Expiration |
|---|---|---|---|---|
| | | (Millions of Dollars) | | |
| Wisconsin Energy | $857.5 | $1.5 | $856.0 | April 2011 |
| | $476.4 | $4.1 | $472.3 | March 2011 |

| | | | | |
|---|---|---|---|---|
| Wisconsin Electric | | | | |
| Wisconsin Gas | $285.8 | $ - | $285.8 | March 2011 |

* Excludes Lehman's commitments

The following table shows our capitalization structure as of March 31, 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 | $3,439.6 | $3,689.6 |
| Preferred Stock of Subsidiary | 30.4 | 30.4 |
| Long-Term Debt (including current maturities) | 4,095.7 | 3,845.7 |
| Short-Term Debt | 791.3 | 791.3 |
| Total Capitalization | $8,357.0 | $8,357.0 |
| Total Debt | $4,887.0 | $4,637.0 |
| Ratio of Debt to Total Capitalization | 58.5% | 55.5% |

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of March 31, 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.

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 9 -- Guarantees and Note 11 -- 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 $22.8 billion as of March 31, 2009 compared with $23.1 billion as of December 31, 2008. Our total contractual obligations and other commercial commitments as of March 31, 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 quarter.



## 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 by We Power. We Power will lease the new units to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the 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 conducting a detailed analysis of Bechtel's force majeure claim 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 it could not have reasonably 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.



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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 have since agreed with Bechtel to combine these issues and Bechtel's claim into one mediation. We anticipate mediating all issues before the end of the year and if this is unsuccessful, the contract calls for binding arbitration which we anticipate will be concluded in 2010.

Bechtel continues to target an in-service date for unit 1 three months beyond the guaranteed contract date of September 29, 2009, and an in-service date for unit 2 one month earlier than the guaranteed contract date of September 29, 2010. Although Bechtel has made significant progress in much of the construction plan, it has fallen behind in moving from construction to start-up. Bechtel has informed us that it has developed a recovery plan and is adding resources in an effort to recover the lost time.

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 has 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.

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.

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. Based on three months of actual fuel cost data and nine months of projected data, Wisconsin Electric forecasts that its monitored fuel cost for 2009 will fall outside the range prescribed by the PSCW and will be less than the monitored fuel cost reflected in currently 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 March 31, 2009, we have issued approximately $352.3 million of bill credits to Wisconsin retail customers.

Michigan Price Increase

: In January, 2008, Wisconsin Electric filed a rate increase request with the MPSC. This request represents an increase in electric rates of 14.7%, or $22.0 million, to support the



growing demand for electricity, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational expenses. In November 2008, a settlement agreement with the MPSC staff and intervenors for a rate increase of $7.2 million, or 4.6%, was approved by the MPSC, effective January 1, 2009.

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 that was billed in 2008 plus $10.0 million of MISO RSG credits that may be received during 2009. We expect to refund approximately $18.8 million to customers by the end of 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 originally estimated the cost of this project to be $750 million ($830 million, including AFUDC). We now expect the cost of completing this project to be approximately $800 million ($960 million including AFUDC). The cost increase is primarily attributable to increases in material prices that occurred prior to the commencement of construction and material procurement activities in July 2008. The increase in AFUDC is based on our updated calculation that assumes AFUDC will accrue on 100% of the construction cost until the facilities are placed in service, which is consistent with the 2010 rate case filing. The cost of constructing these facilities 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 determine 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 late 2009 or early 2010. We do not expect the new depreciation rates to have a material impact on earnings because we anticipate that the new depreciation rates will be considered when the PSCW sets our 2010 electric and gas prices.

See Factors Affecting Results, Liquidity and Capital Resources -- 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.

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 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 is expected to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market is also expected to enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by LSEs located in the service territories of each MISO transmission owner. In February 2008, FERC issued several orders confirming that the current transmission cost allocation methodology is just and reasonable and should continue in the future. These orders are subject to appeals.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of RSG charges. FERC ordered MISO to resettle all affected transactions retroactive to the commencement of the energy market. In October 2006 and March 2007, we received additional rulings from FERC on these issues. FERC's rulings have been challenged by MISO and numerous other market participants. MISO commenced with the resettlement of the market in accordance with the orders in July 2007. 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 orders 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. This resettlement period is expected to conclude in January 2010. Based on our analysis of the FERC decision and MISO's proposed implementation of FERC's ruling, we estimate that there could be a refund to us of up to $17 million. Due to the uncertainty around the ultimate outcome of the RSG cost allocation, we have not reflected the potential impact of this potential resettlement on our financial statements as of March 31, 2009.

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

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through 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, 2008 through May 31, 2009.



The resulting ARR valuation and the secured FTRs should adequately mitigate our transmission congestion risk for that period.

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. We believe compliance with the $NO_x$ emission reduction requirements under the Consent Decree will substantially mitigate 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. We do not anticipate any further requirements to reduce emissions as a result of this finding, but we are unable to predict that outcome until Wisconsin responds to this finding (expected in July 2009) and the EPA subsequently takes a final approval action. In March 2008, the EPA announced its decision to further lower the 8-hour ozone standard. Although additional counties may be designated as non-attainment areas under the revised standard, until those designations become final and until any potential additional rules are adopted, we are unable to predict the impact on the operation of our existing coal-fired generation facilities.

$PM_{2.5}$

***Standard:*** In December 2004, the EPA designated $PM_{2.5}$ non-attainment areas in the country. All counties in Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. In December 2006, a more restrictive federal standard became effective; however, on February 24, 2009 the D.C. Circuit Court of Appeals issued a decision on the revised standard and remanded it back to the EPA for revision. The court's decision will likely result in an even more stringent annual $PM_{2.5}$ standard. Until such time as the EPA revises the standard consistent with the court's decision and the states develop rules and submit SIPs to the EPA to demonstrate how they intend to comply with the standard, we are unable to predict the impact of this more restrictive standard on the operation of our existing coal-fired generation facilities or 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.

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.

EPA Advance Notice of Proposed Rulemaking:

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

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

A decision to regulate greenhouse gas emissions under one section of the CAA could lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants like electric generating plants. Although we cannot predict at this time what impact such a finding or any subsequent rulemaking will have on us, we would expect it to be negative.

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 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 Item 2. 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.

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 months ended March 31, 2009.

ISSUER PURCHASES OF EQUITY SECURITIES

| 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) |
| January 1- January 31 | 869 | $42.17 | - | $ - |
| | | | - | |

| | | | | |
|---|---|---|---|---|
| February 1-<br>February 29 | 340 | $45.58 | | $ - |
| March 1-<br>March 31 | - | $ - | - | $ - |
| Total | 1,209 | $43.19 | - | $ - |

(a) This table does not include shares purchased by independent agents to satisfy obligations under our employee benefit plans and stock purchase and dividend reinvestment plan. 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.

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: May 7, 2009

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