

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

**FORM 10-Q**

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

For the Quarterly Period Ended **September 30, 2011**

<u>Commission File Number</u>	<u>Registrant; State of Incorporation Address; and Telephone Number</u>	<u>IRS Employer Identification No.</u>
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001-01245	<b>WISCONSIN ELECTRIC POWER COMPANY</b> (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 2046 Milwaukee, WI 53201 (414) 221-2345	39-0476280
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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.  
Yes  No

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

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (September 30, 2011):

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

**WISCONSIN ELECTRIC POWER COMPANY**

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**FORM 10-Q REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2011**

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## DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

### **Primary Subsidiary and Affiliates**

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

### **Other Affiliates**

ATC	American Transmission Company LLC
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### **Federal and State Regulatory Agencies**

DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

### **Environmental Terms**

BTA	Best Technology Available
CAMR	Clean Air Mercury Rule
CSAPR	Cross-State Air Pollution Rule
MACT	Maximum Achievable Control Technology
NAAQS	National Ambient Air Quality Standards
SO <sub>2</sub>	Sulfur Dioxide

### **Other Terms and Abbreviations**

AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Compensation Committee	Compensation Committee of the Board of Directors of Wisconsin Energy
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
OC 2	Oak Creek expansion Unit 2
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	<i>Power the Future</i>
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.

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**DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS**

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

**Measurements**

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

**Accounting Terms**

AFUDC	Allowance for Funds Used During Construction
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (Exchange Act). These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, on-going legal proceedings, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "should" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as catastrophic weather-related or terrorism-related damage; cyber-security threats; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.
- Factors affecting the demand for electricity and natural gas, including weather and other natural phenomena; the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; and energy conservation efforts.
- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with Wisconsin Energy Corporation's (Wisconsin Energy) *Power the Future* (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.
- Increased competition in our electric and gas markets and continued industry consolidation.
- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.
- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations under the Energy Policy Act and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.
- Internal restructuring options that may be pursued by Wisconsin Energy.

**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION -- (CONT'D)**

- Current and future litigation, regulatory investigations, proceedings or inquiries, including the pending lawsuit against the Wisconsin Energy Corporation Retirement Account Plan (Plan), FERC matters, and IRS audits and other tax matters.
- Events in the global credit markets that may affect the availability and cost of capital.
- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry or us; and our credit ratings.
- The investment performance of Wisconsin Energy's pension and other post-retirement benefit trusts.
- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.
- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act and any regulations promulgated thereunder.
- The impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 and any related regulations.
- The effect of accounting pronouncements issued periodically by standard setting bodies, including any changes in regulatory accounting policies and practices and any requirement for U.S. registrants to follow International Financial Reporting Standards instead of Generally Accepted Accounting Principles (GAAP).
- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters.
- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents, including the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2010.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

## INTRODUCTION

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

We conduct our operations primarily in three operating segments: an electric utility segment, a natural gas utility segment and a steam utility segment. We serve approximately 1,120,200 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 464,500 gas customers in Wisconsin and approximately 460 steam customers in metropolitan Milwaukee, Wisconsin. For further financial information about our business segments, see Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 -- Segment Information in the Notes to Consolidated Condensed Financial Statements in this report.

Wisconsin Energy is also the parent company of Wisconsin Gas LLC (Wisconsin Gas), a natural gas distribution utility, which serves customers throughout Wisconsin; and W.E. Power, LLC (We Power), an unregulated company that was formed in 2001 to design, construct, own and lease to us the new generating capacity included in Wisconsin Energy's PTF strategy, which is described further in this report and in our 2010 Annual Report on Form 10-K. We have combined common functions with Wisconsin Gas and operate under the trade name of "We Energies."

Bostco is our non-utility subsidiary that develops and invests in real estate. As of September 30, 2011, Bostco had \$34.3 million of assets.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC. We have condensed or omitted some information and note disclosures normally included in financial statements prepared in accordance with GAAP pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2010 Annual Report on Form 10-K, including the financial statements and notes therein.

**PART I -- FINANCIAL INFORMATION****ITEM 1. FINANCIAL STATEMENTS****WISCONSIN ELECTRIC POWER COMPANY  
CONSOLIDATED CONDENSED INCOME STATEMENTS**

(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Operating Revenues	\$ 958.3	\$ 883.2	\$ 2,817.8	\$ 2,594.7
Operating Expenses				
Fuel and purchased power	352.1	336.8	908.1	875.0
Cost of gas sold	28.3	27.0	224.7	218.7
Other operation and maintenance	353.0	356.1	1,062.2	1,051.4
Depreciation and amortization	54.9	54.3	164.1	162.1
Property and revenue taxes	26.9	24.6	79.1	72.7
Total Operating Expenses	815.2	798.8	2,438.2	2,379.9
Amortization of Gain	—	55.2	—	151.8
Operating Income	143.1	139.6	379.6	366.6
Equity in Earnings of Transmission Affiliate	13.7	13.4	40.7	40.0
Other Income, net	16.2	9.5	42.2	25.2
Interest Expense, net	22.8	25.5	70.3	77.1
Income Before Income Taxes	150.2	137.0	392.2	354.7
Income Taxes	49.1	47.4	125.5	124.3
Net Income	101.1	89.6	266.7	230.4
Preferred Stock Dividend Requirement	0.3	0.3	0.9	0.9
Earnings Available for Common Stockholder	\$ 100.8	\$ 89.3	\$ 265.8	\$ 229.5

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

**WISCONSIN ELECTRIC POWER COMPANY**  
**CONSOLIDATED CONDENSED BALANCE SHEETS**

(Unaudited)

	September 30, 2011	December 31, 2010
<u>Assets</u>	(Millions of Dollars)	
Property, Plant and Equipment		
In service	\$ 7,950.7	\$ 7,885.4
Accumulated depreciation	(2,930.2)	(2,879.7)
	5,020.5	5,005.7
Construction work in progress	1,178.2	803.3
Leased facilities, net	2,452.5	1,850.7
Net Property, Plant and Equipment	8,651.2	7,659.7
Investments		
Equity investment in transmission affiliate	304.5	290.6
Other	0.2	0.5
Total Investments	304.7	291.1
Current Assets		
Cash and cash equivalents	13.1	23.3
Restricted cash	45.5	8.3
Accounts receivable, net	267.6	260.4
Accounts receivable from related parties	28.7	23.3
Accrued revenues	149.1	208.7
Materials, supplies and inventories	293.0	321.8
Prepayments	143.8	131.0
Other	46.7	67.4
Total Current Assets	987.5	1,044.2
Deferred Charges and Other Assets		
Regulatory assets	1,085.5	1,009.0
Other	157.7	166.7
Total Deferred Charges and Other Assets	1,243.2	1,175.7
Total Assets	\$ 11,186.6	\$ 10,170.7
<u>Capitalization and Liabilities</u>		
Capitalization		
Common equity	\$ 3,160.2	\$ 3,065.1
Preferred stock	30.4	30.4
Long-term debt	2,267.1	1,970.9
Capital lease obligations	2,721.5	2,060.8
Total Capitalization	8,179.2	7,127.2
Current Liabilities		
Long-term debt and capital lease obligations due currently	33.6	21.8
Short-term debt	121.0	210.5
Subsidiary note payable to Wisconsin Energy	27.3	27.6
Accounts payable	232.5	234.8
Accounts payable to related parties	88.7	83.7
Other	248.0	208.4
Total Current Liabilities	751.1	786.8
Deferred Credits and Other Liabilities		
Regulatory liabilities	684.2	658.1
Deferred income taxes - long-term	1,146.0	925.4
Pension and other benefit obligations	175.9	403.7
Other	250.2	269.5
Total Deferred Credits and Other Liabilities	2,256.3	2,256.7
Total Capitalization and Liabilities	\$ 11,186.6	\$ 10,170.7

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

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

	Nine Months Ended September 30	
	2011	2010
	(Millions of Dollars)	
Operating Activities		
Net income	\$ 266.7	\$ 230.4
Reconciliation to cash		
Depreciation and amortization	165.2	168.2
Amortization of gain	—	(151.8)
Equity in earnings of transmission affiliate	(40.7)	(40.0)
Distributions from transmission affiliate	32.5	32.4
Deferred income taxes and investment tax credits, net	154.6	(13.2)
Contributions to qualified benefit plans	(242.1)	—
Change in - Accounts receivable and accrued revenues	40.1	23.3
Inventories	28.8	(25.5)
Other current assets	14.3	42.1
Accounts payable	0.7	1.7
Accrued income taxes, net	(36.6)	14.2
Deferred costs, net	19.4	19.5
Other current liabilities	22.7	20.2
Other, net	48.8	41.3
Cash Provided by Operating Activities	474.4	362.8
Investing Activities		
Capital expenditures	(522.3)	(396.9)
Investment in transmission affiliate	(5.8)	(3.5)
Proceeds from asset sales	38.5	0.6
Change in restricted cash	(37.2)	131.8
Other, net	(37.2)	(29.8)
Cash Used in Investing Activities	(564.0)	(297.8)
Financing Activities		
Dividends paid on common stock	(134.7)	(134.7)
Dividends paid on preferred stock	(0.9)	(0.9)
Issuance of long-term debt	300.0	—
Change in total short-term debt	(89.9)	(47.7)
Capital contribution from parent	—	100.0
Other, net	4.9	10.7
Cash Provided by (Used in) Financing Activities	79.4	(72.6)
Change in Cash and Cash Equivalents	(10.2)	(7.6)
Cash and Cash Equivalents at Beginning of Period	23.3	18.3
Cash and Cash Equivalents at End of Period	\$ 13.1	\$ 10.7

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

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

**1 -- GENERAL INFORMATION**

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8, Financial Statements and Supplementary Data, in our 2010 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of the results which may be expected for the entire fiscal year 2011 because of seasonal and other factors.

**2 -- NEW ACCOUNTING PRONOUNCEMENTS**

No new accounting pronouncements were issued or adopted during the first nine months of 2011 which would have a material impact on our financial condition, results of operations or cash flows.

**3 -- COMMON EQUITY**

On January 20, 2011, Wisconsin Energy's Board of Directors declared a two-for-one stock split effected by a 100% stock dividend paid on March 1, 2011 to shareholders of record on February 14, 2011. All share and per share data related to Wisconsin Energy equity compensation awards in these financial statements have been restated to reflect the stock split.

**Share-Based Compensation Expense:** For a description of share-based compensation, including Wisconsin Energy stock options, restricted stock and performance units, see Note H -- Common Equity in our 2010 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period. There were no modifications to the terms of outstanding Wisconsin Energy stock options held by our employees during the period other than the necessary adjustments as a result of Wisconsin Energy's stock split.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Stock options	\$ 0.6	\$ 1.8	\$ 1.8	\$ 5.2
Performance units	6.1	9.7	9.8	19.7
Restricted stock	0.3	0.2	0.9	0.6
Share-based compensation expense	<u>\$ 7.0</u>	<u>\$ 11.7</u>	<u>\$ 12.5</u>	<u>\$ 25.5</u>
Related tax benefit	<u>\$ 2.8</u>	<u>\$ 4.6</u>	<u>\$ 5.0</u>	<u>\$ 10.2</u>

**Stock Option Activity:** During the first nine months of 2011, the Compensation Committee of the Board of Directors of Wisconsin Energy (Compensation Committee) granted 435,370 Wisconsin Energy non-qualified stock options to our employees that had an estimated fair value of \$3.17 per share. During the first nine months of 2010, the Compensation Committee granted 514,700 Wisconsin Energy stock options to our employees that had an estimated fair value of \$3.36 per share. The following assumptions were used to value the Wisconsin Energy options using a binomial option pricing model:

	2011	2010
Risk-free interest rate	0.2% - 3.4%	0.2% - 3.9%
Dividend yield	3.9%	3.7%
Expected volatility	19.0%	20.3%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	5.5	5.9

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

The following is a summary of Wisconsin Energy stock option activity by our employees during the three and nine months ended September 30, 2011:

Stock Options	Number of Options	Weighted- Average Exercise Price	Weighted- Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of July 1, 2011	10,998,682	\$ 21.55		
Granted	—	\$ —		
Exercised	(215,972)	\$ 17.81		
Forfeited	—	\$ —		
Outstanding as of September 30, 2011	<u>10,782,710</u>	\$ 21.62		
Outstanding as of January 1, 2011	12,034,614	\$ 20.95		
Granted	435,370	\$ 29.35		
Exercised	(1,687,274)	\$ 18.81		
Forfeited	—	\$ —		
Outstanding as of September 30, 2011	<u>10,782,710</u>	\$ 21.62	5.6	\$ 104.2
Exercisable as of September 30, 2011	<u>7,794,520</u>	\$ 21.14	4.7	\$ 79.1

The intrinsic value of Wisconsin Energy options exercised by our employees was \$3.0 million and \$20.6 million for the three and nine months ended September 30, 2011, and \$22.6 million and \$43.6 million for the same periods in 2010, respectively. Cash received by Wisconsin Energy from exercises of its options by our employees was \$31.7 million and \$66.7 million during the nine months ended September 30, 2011 and 2010, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately \$8.2 million and \$17.4 million, respectively.

The following table summarizes information about Wisconsin Energy stock options held by our employees and outstanding as of September 30, 2011:

Range of Exercise Prices	Options Outstanding			Options Exercisable		
	Number of Options	Weighted-Average		Number of Options	Weighted-Average	
		Exercise Price	Remaining Contractual Life (Years)		Exercise Price	Remaining Contractual Life (Years)
\$11.33 to \$17.10	2,098,188	\$ 16.25	2.6	2,098,188	\$ 16.25	2.6
\$19.74 to \$21.11	3,531,782	\$ 20.61	6.2	1,447,422	\$ 19.89	4.6
\$23.88 to \$29.35	5,152,740	\$ 24.51	6.3	4,248,910	\$ 23.98	5.8
	<u>10,782,710</u>	\$ 21.62	5.6	<u>7,794,520</u>	\$ 21.14	4.7

The following table summarizes information about our employees' non-vested Wisconsin Energy stock options during the three and nine months ended September 30, 2011:

Non-Vested Stock Options	Number of Options	Weighted-Average	
			Fair Value
Non-vested as of July 1, 2011	2,988,190	\$	3.78
Granted	—	\$	—
Vested	—	\$	—
Forfeited	—	\$	—
Non-vested as of September 30, 2011	<u>2,988,190</u>	\$	3.78
Non-vested as of January 1, 2011	4,996,650	\$	4.27
Granted	435,370	\$	3.17
Vested	(2,443,830)	\$	4.66
Forfeited	—	\$	—
Non-vested as of September 30, 2011	<u>2,988,190</u>		

As of September 30, 2011, our total compensation costs related to non-vested Wisconsin Energy stock options held by our employees and not yet recognized was approximately \$1.2 million, which is expected to be recognized over the next 14 months on a weighted-average basis.

**Restricted Shares:** The Compensation Committee also approved Wisconsin Energy restricted stock grants to certain of our key employees. These awards have a three-year vesting period, with one-third of the award vesting on each anniversary of the grant date. During the vesting period, restricted share recipients have voting rights and are entitled to dividends in the same manner as other shareholders.

The following restricted stock activity related to our employees occurred during the three and nine months ended September 30, 2011:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value	
Outstanding as of July 1, 2011	121,780		
Granted	—	\$	—
Released	—	\$	—
Forfeited	—	\$	—
Outstanding as of September 30, 2011	<u>121,780</u>		
Outstanding as of January 1, 2011	124,460		
Granted	51,690	\$	29.00
Released	(52,494)	\$	16.63
Forfeited	(1,876)	\$	25.89
Outstanding as of September 30, 2011	<u>121,780</u>		

Wisconsin Energy records the market value of the restricted stock awards on the date of grant and then we amortize our share of allocated expense over the vesting period of the awards. The intrinsic value of Wisconsin Energy restricted stock vesting and held by our employees was zero and \$1.5 million for the three and nine months ended September 30, 2011, and \$0.1 million and \$0.3 million for the same periods in 2010. The actual tax benefit realized for the tax deductions from released restricted shares for the same periods was zero and \$0.6 million for the three and nine months ended September 30, 2011, and zero and \$0.1 million for the same periods in 2010, respectively.

As of September 30, 2011, total compensation cost related to our share of Wisconsin Energy restricted stock not yet recognized was approximately \$2.0 million, which is expected to be recognized over the next 23 months on a weighted-average basis.

**Performance Units:** In January 2011 and 2010, the Compensation Committee awarded 413,990 and 520,620 Wisconsin Energy performance units, respectively, to our officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units which will be awarded is dependent upon the achievement of certain financial performance of Wisconsin Energy's common stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing our share of compensation costs over the three-year period based on our estimate of the final expected value of the award. Performance units earned as of December 31, 2010 and 2009 vested and were settled during the first quarter of 2011 and 2010, and had a total intrinsic value of \$12.1 million and \$9.3 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately \$4.2 million and \$3.2 million, respectively. As of September 30, 2011, total compensation cost related to our share of Wisconsin Energy performance units not yet recognized was approximately \$16.2 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

**Restrictions:** Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note H -- Common Equity in our 2010 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. During the nine months ended September 30, 2011 and 2010, total comprehensive income was equal to net income.

#### 4 -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

In September 2011, we issued \$300 million of 2.95% Debentures due September 15, 2021. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other general corporate purposes.

On January 12, 2011, Oak Creek expansion Unit 2 (OC 2) was placed into service. We now have care, custody and control of OC 2 and will operate and maintain it over the 30 year life of the lease. As a result of the commercial operation of OC 2, in January 2011, we recorded an additional capital lease asset and capital lease obligation related to the Oak Creek expansion totaling approximately \$650 million. The lease payments are expected to be recovered through our rates, as supported by the Wisconsin 2001 Leased Generation Law. The total obligation under the capital lease for the Oak Creek expansion was approximately \$2.0 billion as of September 30, 2011 and will decrease to zero over the remaining life of the contract.

#### 5 -- DIVESTITURES

**Edgewater Generating Unit 5:** On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company (WPL) for our net book value, including working capital, of approximately \$38 million.

#### 6 -- FAIR VALUE MEASUREMENTS

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

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

Assets and liabilities measured and reported at fair value are classified and disclosed in one of the following categories:

Level 1 -- Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an on-going basis. Instruments in this category consist of financial instruments such as exchange-traded derivatives, cash equivalents and restricted cash investments.

Level 2 -- Pricing inputs are other than quoted prices in active markets, which are either directly or indirectly observable as of the reporting date, and fair value is determined through the use of models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as Over-the-Counter (OTC) forwards and options.

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to fair value reporting and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, an instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the instrument.

The following tables summarize our financial assets and liabilities by level within the fair value hierarchy:

Recurring Fair Value Measures	As of September 30, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$ 45.5	\$ —	\$ —	\$ 45.5
Derivatives	0.5	1.8	10.1	12.4
Total	\$ 46.0	\$ 1.8	\$ 10.1	\$ 57.9
Liabilities:				
Derivatives	\$ 4.4	\$ 0.2	\$ —	\$ 4.6
Total	\$ 4.4	\$ 0.2	\$ —	\$ 4.6

Recurring Fair Value Measures	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$ 8.3	\$ —	\$ —	\$ 8.3
Derivatives	4.5	3.7	5.9	14.1
Total	\$ 12.8	\$ 3.7	\$ 5.9	\$ 22.4
Liabilities:				
Derivatives	\$ 3.0	\$ 3.3	\$ —	\$ 6.3
Total	\$ 3.0	\$ 3.3	\$ —	\$ 6.3

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents (i) for 2010, the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of the Point Beach Nuclear Power Plant (Point Beach), and (ii) for 2011, the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which will be returned, net of costs incurred, to customers. 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 table summarizes the fair value of derivatives classified as Level 3 in the fair value hierarchy:

	Quarter to Date		Year to Date	
	2011	2010	2011	2010
	(Millions of Dollars)			
Beginning Balance	\$ 14.6	\$ 15.9	\$ 5.9	\$ 5.8
Realized and unrealized gains (losses)	—	—	—	—
Purchases, issuances and settlements	(4.5)	(5.5)	4.2	4.6
Transfers in and/or out of Level 3	—	—	—	—
Balance as of September 30	<u>\$ 10.1</u>	<u>\$ 10.4</u>	<u>\$ 10.1</u>	<u>\$ 10.4</u>
Change in unrealized gains (losses) relating to instruments still held as of September 30	\$ —	\$ —	\$ —	\$ —

Derivative instruments reflected in Level 3 of the hierarchy include MISO Financial Transmission Rights (FTRs) that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note 7 -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

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

Financial Instruments	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	\$ 30.4	\$ 22.9	\$ 30.4	\$ 23.5
Long-term debt, including current portion	\$ 2,287.0	\$ 2,641.8	\$ 1,987.0	\$ 2,158.7

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

## 7 -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the Public Service Commission of Wisconsin (PSCW).

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of September 30, 2011, we recognized \$9.5 million in regulatory assets and \$14.3 million in regulatory liabilities related to derivatives in comparison to \$11.0 million in regulatory assets and \$13.7 million in regulatory liabilities as of December 31, 2010.

We record our current derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. We had no long-term portion of derivative assets as of September 30, 2011, and

the long-term portion of our derivative liabilities of \$0.3 million is recorded in Other deferred credits and other liabilities as of September 30, 2011. Our Consolidated Condensed Balance Sheets as of September 30, 2011 and December 31, 2010 include:

	September 30, 2011		December 31, 2010	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	\$ 1.2	\$ 4.6	\$ 0.9	\$ 6.3
Fuel Oil	0.5	—	4.4	—
FTRs	10.1	—	5.9	—
Coal	0.6	—	2.9	—
Total	<u>\$ 12.4</u>	<u>\$ 4.6</u>	<u>\$ 14.1</u>	<u>\$ 6.3</u>

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under Fuel and purchased power for those commodities supporting our electric operations and under Cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the three and nine months ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30, 2011		Three Months Ended September 30, 2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
	(Millions of Dollars)			
Natural Gas	7.6 million Dth	\$ (7.5)	8.5 million Dth	\$ (4.6)
Power	zero MWh	—	65,040 MWh	(0.5)
Fuel Oil	2.2 million gallons	2.4	2.3 million gallons	(0.1)
FTRs	5,896 MW	5.2	6,584 MW	4.4
Total		<u>\$ 0.1</u>		<u>\$ (0.8)</u>

	Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
	(Millions of Dollars)			
Natural Gas	24.4 million Dth	\$ (15.3)	30.0 million Dth	\$ (18.7)
Power	zero MWh	—	224,640 MWh	(0.5)
Fuel Oil	8.8 million gallons	4.9	6.0 million gallons	(0.1)
FTRs	18,439 MW	10.5	18,673 MW	16.2
Total		<u>\$ 0.1</u>		<u>\$ (3.1)</u>

As of September 30, 2011 and December 31, 2010, we posted collateral of \$5.9 million and \$4.2 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in Other current assets.

## 8 -- BENEFITS

The components of our net periodic pension and Other Post-Retirement Employee Benefits (OPEB) costs for the three and nine months ended September 30 were as follows:

Benefit Plan Cost Components	Pension Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	\$ 3.6	\$ 5.6	\$ 10.9	\$ 16.6
Interest cost	14.6	14.8	43.8	44.3
Expected return on plan assets	(16.0)	(14.9)	(47.9)	(44.7)
Amortization of:				
Prior service cost	0.5	0.5	1.6	1.6
Actuarial loss	6.2	4.7	18.3	14.1
Net Periodic Benefit Cost	<u>\$ 8.9</u>	<u>\$ 10.7</u>	<u>\$ 26.7</u>	<u>\$ 31.9</u>

Benefit Plan Cost Components	OPEB Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	\$ 2.5	\$ 2.7	\$ 7.5	\$ 8.0
Interest cost	4.3	4.3	12.8	13.0
Expected return on plan assets	(2.8)	(2.3)	(8.4)	(6.9)
Amortization of:				
Transition obligation	—	0.1	0.2	0.3
Prior service (credit)	(0.4)	(3.0)	(1.4)	(8.9)
Actuarial loss	0.9	2.1	3.0	6.2
Net Periodic Benefit Cost	<u>\$ 4.5</u>	<u>\$ 3.9</u>	<u>\$ 13.7</u>	<u>\$ 11.7</u>

In January 2011, we contributed \$107.1 million to our qualified benefit plans. In September 2011, we contributed \$135.0 million to our qualified 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.

**Postemployment Benefits:** Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was \$9.5 million as of September 30, 2011 and \$10.7 million as of December 31, 2010.

## 9 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties. As of September 30, 2011, we had the following guarantees:

	Maximum Potential			Liability Recorded
	Future Payments	Outstanding	(Millions of Dollars)	
Guarantees	\$ 2.8	\$ 0.1		\$ —
Letters of Credit	\$ 1.5	\$ 0.7		\$ —

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

## 10 -- SEGMENT INFORMATION

Summarized financial information concerning our operating segments for the three and nine months ended September 30, 2011 and 2010 is shown in the following table:

	Operating Segments			Total
	Electric	Gas	Steam	
(Millions of Dollars)				
Three Months Ended				
September 30, 2011				
Operating Revenues (a)	\$ 900.2	\$ 51.8	\$ 6.3	\$ 958.3
Operating Income (Loss)	\$ 150.1	\$ (5.6)	\$ (1.4)	\$ 143.1
September 30, 2010				
Operating Revenues (a)	\$ 827.2	\$ 50.1	\$ 5.9	\$ 883.2
Operating Income (Loss)	\$ 148.8	\$ (6.3)	\$ (2.9)	\$ 139.6
Nine Months Ended				
September 30, 2011				
Operating Revenues (a)	\$ 2,439.4	\$ 349.4	\$ 29.0	\$ 2,817.8
Operating Income	\$ 343.9	\$ 34.5	\$ 1.2	\$ 379.6
September 30, 2010				
Operating Revenues (a)	\$ 2,232.7	\$ 334.5	\$ 27.5	\$ 2,594.7
Operating Income	\$ 342.0	\$ 23.0	\$ 1.6	\$ 366.6

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

As of September 30, 2011, our total assets in our electric utility segment increased by approximately \$1.0 billion as compared to December 31, 2010 primarily because of the commencement of commercial operation of OC 2 in January 2011, at which time we recorded an additional capital lease asset of approximately \$650 million, and an increase of approximately \$375 million in construction work in progress.

## 11 -- VARIABLE INTEREST ENTITIES

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

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

We have identified two tolling and purchased power agreements with third parties that represent variable interests. We account for one of these agreements, with an independent power producer, as an operating lease. The agreement has a remaining term of two years. We have examined the risks of the entity including the impact of operations and maintenance, dispatch, financing, fuel costs, remaining useful life and other factors, and have determined that we are not the primary beneficiary of this entity. We have concluded that we do not have the power to direct the activities that would most significantly affect the economic performance of the entity over its remaining life.

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the remaining term of 11 years. We have examined the risks of the entity including operations and maintenance, dispatch, financing, fuel costs and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity and there is no residual guarantee associated with the purchased power agreement.

We have approximately \$321.6 million of required payments over the remaining term of these agreements. We believe that the required lease payments under these contracts will continue to be recoverable in rates. Total capacity and lease payments under these contracts for the nine months ended September 30, 2011 and 2010 were \$51.0 million and \$49.6 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

## 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 statements as a whole.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal-combustion product disposal sites. We perform ongoing assessments of our manufactured gas plant sites and related disposal sites, as well as our coal combustion product disposal/landfill sites. We are working with the Wisconsin Department of Natural Resources (WDNR) in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

**Manufactured Gas Plant Sites:** We have identified several sites at which we or a predecessor company historically owned or operated a manufactured gas plant. We have substantially completed planned remediation activities at some of these sites and certain other sites are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from \$10 million to \$25 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of September 30, 2011, we have established reserves of \$13.7 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including us, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly,

we have recorded a regulatory asset for remediation costs.

**Indemnifications:** In connection with the sale of Point Beach, we agreed to provide the buyer with indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5.

**Cash Balance Pension Plan:** In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff has sought class certification for other similarly situated plaintiffs. The complaint alleges that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of the Employee Retirement Income Security Act of 1974 (ERISA) and are owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant. The plaintiff has not specified the amount of relief he is seeking.

In March 2011, after the matter was addressed by the Plan's Employee Benefits Committee and following the Committee's review and analysis of the facts and evolving state of the law, the Plan acknowledged in an amended answer that it had used an incorrect interest crediting rate in computing lump sum payments prior to normal retirement age. The Committee determined the interest crediting rates that should be applied to address the interest crediting rate calculation and determined that the benefits for certain eligible participants should be recalculated. The plaintiff is opposing the Committee's actions and the Court has not yet decided what deference, if any, to give to the Committee's decision. In the meantime, the parties have engaged in mediation and are exploring settlement opportunities. We are currently unable to predict the final outcome or impact of this litigation. While an adverse outcome of this lawsuit could have a material adverse effect on Plan funding and future expense, we do not believe that the resolution of this matter will cost more than \$20 million in 2011.

**Income Taxes:** During 2011, our state and federal unrecognized tax benefits decreased by approximately \$4.1 million exclusive of accrued interest. This decrease primarily relates to the payment of a state tax obligation and the result of effective settlements with state and federal taxing authorities.

### 13 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2011, we paid \$40.8 million in interest, net of amounts capitalized, and received \$1.2 million in net refunds from income taxes. During the nine months ended September 30, 2010, we paid \$48.2 million in interest, net of amounts capitalized, and \$107.4 million in income taxes, net of refunds.

As of September 30, 2011 and 2010, the amount of accounts payable related to capital expenditures was \$18.7 million and \$16.0 million, respectively.

### 14 -- SUBSEQUENT EVENTS

On October 20, 2011, the Wisconsin Electric Board of Directors authorized a special common stock dividend of \$60 million, which was paid on October 31, 2011.

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

**RESULTS OF OPERATIONS -- THREE MONTHS ENDED SEPTEMBER 30, 2011**

**Electric Utility Revenues and Sales**

The following table compares electric utility operating revenues and MWh sales by customer class during the third quarter of 2011 with the third quarter of 2010, including favorable (better (B)) or unfavorable (worse (W)) variances:

Electric Utility Operations	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$ 339.8	\$ 10.5	\$ 329.3	2,451.1	(57.4)	2,508.5
Small Commercial/Industrial	279.0	27.2	251.8	2,439.7	25.3	2,414.4
Large Commercial/Industrial	209.6	21.6	188.0	2,711.6	8.0	2,703.6
Other - Retail	5.3	0.3	5.0	35.7	0.1	35.6
Total Retail	833.7	59.6	774.1	7,638.1	(24.0)	7,662.1
Wholesale - Other	38.5	2.9	35.6	487.9	(48.7)	536.6
Resale - Utilities	20.9	10.1	10.8	525.4	332.2	193.2
Other Operating Revenues	7.1	0.4	6.7	—	—	—
Total	<u>\$ 900.2</u>	<u>\$ 73.0</u>	<u>\$ 827.2</u>	<u>8,651.4</u>	<u>259.5</u>	<u>8,391.9</u>
Weather -- Degree Days (a)						
Heating (126 Normal)				156	38	118
Cooling (527 Normal)				673	(60)	733

(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 \$73.0 million, or 8.8%, when compared to the third quarter of 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately \$55.2 million, reflecting the reduction of Point Beach bill credits to retail customers.
- Net pricing increases totaling \$8.1 million, which includes rates to recover the increase in 2011 fuel costs that became effective April 29, 2011. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters.
- Unfavorable weather as compared to the prior year that decreased electric revenues by an estimated \$17.7 million.
- A \$10.1 million increase in revenue from energy sold into the MISO energy market, which was driven by increased MWh generation from the Oak Creek expansion units.

As measured by cooling degree days, the third quarter of 2011 was 27.7% hotter than normal, but 8.2% cooler than the same period in 2010. The decrease in residential sales volumes in 2011 is primarily attributable to the cooler weather. Growth in sales to our small commercial/industrial customers during the third quarter of 2011 reflects economic improvement over the third quarter of 2010, which offset the impact of the cooler weather. The increased sales to our largest customers, two iron ore mines, accounted for the increase in sales to our large commercial/industrial customers. If these sales are excluded, sales to our large commercial/industrial customers decreased slightly for the third quarter of 2011 as compared to the third quarter of 2010.

## Fuel and Purchased Power

Our fuel and purchased power costs increased by \$15.3 million, or 4.5%, when compared to the third quarter of 2010. This increase was primarily caused by a 3.1% increase in total MWh sales as well as increased coal and coal transportation costs, partially offset by changes in the mix of MWh generation that resulted in decreased costs as compared to the third quarter of 2010.

## Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the third quarter of 2011 with the third quarter of 2010. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by \$1.7 million, or 3.4%.

	Three Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	\$ 51.8	\$ 1.7	\$ 50.1
Cost of Gas Sold	28.3	(1.3)	27.0
Gross Margin	<u>\$ 23.5</u>	<u>\$ 0.4</u>	<u>\$ 23.1</u>

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the third quarter of 2011 with the third quarter of 2010:

Gas Utility Operations	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$ 15.7	\$ 0.5	\$ 15.2	21.2	1.9	19.3
Commercial/Industrial	3.9	—	3.9	14.0	0.6	13.4
Interruptible	0.1	—	0.1	0.6	(0.2)	0.8
Total Retail	19.7	0.5	19.2	35.8	2.3	33.5
Transported Gas	3.5	(0.1)	3.6	59.5	(14.8)	74.3
Other	0.3	—	0.3	—	—	—
Total	<u>\$ 23.5</u>	<u>\$ 0.4</u>	<u>\$ 23.1</u>	<u>95.3</u>	<u>(12.5)</u>	<u>107.8</u>
Weather -- Degree Days (a)						
Heating (126 Normal)				156	38	118

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

Our gas margin is seasonal and is primarily driven by the heating needs of our customers. The third quarter gas margin is historically the lowest of the year because of the lack of heating load. Our gas margin increased by \$0.4 million, or approximately 1.7%, when compared to the third quarter of 2010.

## Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by \$3.1 million, or approximately 0.9%, when compared to the third quarter of 2010.

## Depreciation and Amortization Expense

Our depreciation and amortization expense increased by \$0.6 million, or approximately 1.1%, when compared to the third quarter of 2010, primarily because of an overall increase in utility plant in service.

## 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 to be used for the benefit of our customers. The majority of the benefits were returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it was amortized to the income statement as we issued bill credits to customers. When the bill credits were issued to customers, we transferred cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. All bill credits associated with the sale of Point Beach were applied to customers as of December 31, 2010, and as a result, the Amortization of Gain was zero during the third quarter of 2011 as compared to \$55.2 million during the third quarter of 2010.

## Other Income, net

Other Income, net	Three Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
AFUDC - Equity	\$ 16.0	\$ 7.3	\$ 8.7
Other	0.2	(0.6)	0.8
Other Income, net	<u>\$ 16.2</u>	<u>\$ 6.7</u>	<u>\$ 9.5</u>

Other income, net increased by \$6.7 million, or approximately 70.5%, when compared to the third quarter of 2010. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek Air Quality Control System (AQCS) project and the Glacier Hills Wind Park.

## Interest Expense, net

Interest Expense	Three Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gross Interest Costs	\$ 29.5	\$ (0.4)	\$ 29.1
Less: Capitalized Interest	6.7	3.1	3.6
Interest Expense, net	<u>\$ 22.8</u>	<u>\$ 2.7</u>	<u>\$ 25.5</u>

Our gross interest costs increased by \$0.4 million, or 1.4%, when compared to the third quarter of 2010. Our capitalized interest increased by \$3.1 million primarily due to increased capital expenditures related to the Oak Creek AQCS project and the Glacier Hills Wind Park during the third quarter of 2011 as compared to the same period in 2010. As a result, our net interest expense decreased by \$2.7 million, or 10.6%, as compared to the third quarter of 2010.

## Income Taxes

For the third quarter of 2011, our effective tax rate was 32.7% compared to 34.6% for the third quarter of 2010, primarily because of the increase in AFUDC - Equity in 2011 over 2010. For additional information, see Note G -- Income Taxes in our 2010 Annual Report on Form 10-K.

## RESULTS OF OPERATIONS -- NINE MONTHS ENDED SEPTEMBER 30, 2011

### Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first nine months of 2011 with the first nine months of 2010:

Electric Utility Operations	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$ 882.6	\$ 40.5	\$ 842.1	6,316.7	(67.0)	6,383.7
Small Commercial/Industrial	766.1	66.8	699.3	6,703.6	(4.8)	6,708.4
Large Commercial/Industrial	581.6	67.2	514.4	7,587.4	60.9	7,526.5
Other - Retail	16.6	0.8	15.8	110.6	(1.2)	111.8
Total Retail	<u>2,246.9</u>	<u>175.3</u>	<u>2,071.6</u>	<u>20,718.3</u>	<u>(12.1)</u>	<u>20,730.4</u>
Wholesale - Other	114.4	7.3	107.1	1,492.8	(80.1)	1,572.9
Resale - Utilities	53.6	19.4	34.2	1,531.6	661.8	869.8
Other Operating Revenues	24.5	4.7	19.8	—	—	—
Total	<u>\$ 2,439.4</u>	<u>\$ 206.7</u>	<u>\$ 2,232.7</u>	<u>23,742.7</u>	<u>569.6</u>	<u>23,173.1</u>
Weather -- Degree Days (a)						
Heating (4,320 Normal)				4,637	704	3,933
Cooling (699 Normal)				786	(155)	941

(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 \$206.7 million, or 9.3%, when compared to the first nine months of 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately \$151.8 million, reflecting the reduction of Point Beach bill credits to retail customers.
- Net pricing increases totaling \$36.9 million, which includes rates related to our 2010 fuel recovery request that became effective March 25, 2010, and our request to review 2011 fuel costs that became effective April 29, 2011. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters.
- Unfavorable weather as compared to the prior year that decreased electric revenues by an estimated \$27.0 million.
- A \$19.4 million increase in revenue from energy sold into the MISO energy market, which was driven by increased MWh generation from the Oak Creek expansion units.

As measured by cooling degree days, the first nine months of 2011 were 12.4% warmer than normal, but 16.5% cooler than the same period in 2010. The decrease in residential sales volumes in 2011 is primarily attributable to the cooler weather. The increased sales to our largest customers, two iron ore mines, accounted for the increase in sales to our large commercial/industrial customers. If these sales are excluded, sales to our large commercial/industrial customers decreased slightly for the first nine months of 2011 as compared to the first nine months of 2010.

### Fuel and Purchased Power

Our fuel and purchased power costs increased by \$33.1 million, or 3.8%, when compared to the first nine months of 2010. This increase was primarily caused by a 2.5% increase in total MWh sales as well as increased coal and coal transportation costs, partially offset by lower natural gas prices.

## Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first nine months of 2011 with the first nine months of 2010. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by \$14.9 million, or 4.5%, primarily because of colder weather during 2011.

	Nine Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	\$ 349.4	\$ 14.9	\$ 334.5
Cost of Gas Sold	224.7	(6.0)	218.7
Gross Margin	<u>\$ 124.7</u>	<u>\$ 8.9</u>	<u>\$ 115.8</u>

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first nine months of 2011 with the first nine months of 2010:

Gas Utility Operations	Nine Months Ended September 30					
	Gross Margin			Therm Deliveries		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$ 83.7	\$ 6.4	\$ 77.3	243.9	32.0	211.9
Commercial/Industrial	27.3	3.0	24.3	140.8	19.3	121.5
Interruptible	0.4	—	0.4	3.9	(0.1)	4.0
Total Retail	111.4	9.4	102.0	388.6	51.2	337.4
Transported Gas	12.0	0.5	11.5	220.3	(5.4)	225.7
Other	1.3	(1.0)	2.3	—	—	—
Total	<u>\$ 124.7</u>	<u>\$ 8.9</u>	<u>\$ 115.8</u>	<u>608.9</u>	<u>45.8</u>	<u>563.1</u>
Weather -- Degree Days (a)						
Heating (4,320 Normal)				4,637	704	3,933

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

Our gas margin increased by \$8.9 million, or 7.7%, when compared to the first nine months of 2010. We estimate that approximately \$8.7 million of this increase relates to an increase in sales volumes as a result of colder weather during the first nine months of 2011 that increased heating loads. As measured by heating degree days, the first nine months of 2011 were 17.9% colder than the same period in 2010 and 7.3% colder than normal.

## Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by \$10.8 million, or approximately 1.0%, when compared to the first nine months of 2010, of which approximately \$5.4 million was attributable to our power plants. In addition, expenses related to our electric distribution system increased by approximately \$4.0 million.

## Depreciation and Amortization Expense

Our depreciation and amortization expense increased by \$2.0 million, or approximately 1.2%, when compared to the first nine months of 2010, primarily because of an overall increase in utility plant in service.

## Amortization of Gain

The Amortization of Gain was zero during the first nine months of 2011 as compared to \$151.8 million during the first nine months of 2010. For additional information, see Amortization of Gain under Results of Operations -- Three Months Ended September 30, 2011.

**Other Income, net**

Other Income, net	Nine Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
AFUDC - Equity	\$ 41.5	\$ 19.5	\$ 22.0
Other	0.7	(2.5)	3.2
Other Income, net	<u>\$ 42.2</u>	<u>\$ 17.0</u>	<u>\$ 25.2</u>

Other income, net increased by \$17.0 million, or approximately 67.5%, when compared to the first nine months of 2010. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

**Interest Expense, net**

Interest Expense	Nine Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gross Interest Costs	\$ 87.6	\$ (1.4)	\$ 86.2
Less: Capitalized Interest	17.3	8.2	9.1
Interest Expense, net	<u>\$ 70.3</u>	<u>\$ 6.8</u>	<u>\$ 77.1</u>

Our gross interest costs increased by \$1.4 million, or 1.6%, during the first nine months of 2011 when compared to the first nine months of 2010. Our capitalized interest increased by \$8.2 million primarily due to increased capital expenditures related to the Oak Creek AQCS project and the Glacier Hills Wind Park during the first nine months of 2011 as compared to the same period in 2010. As a result, our net interest expense decreased by \$6.8 million, or 8.8%, as compared to the first nine months of 2010.

**Income Taxes**

For the first nine months of 2011, our effective tax rate was 32.0% compared to 35.0% for the first nine months of 2010, primarily because of the increase in AFUDC - Equity in 2011 over 2010. For additional information, see Note G -- Income Taxes in our 2010 Annual Report on Form 10-K.

**LIQUIDITY AND CAPITAL RESOURCES****CASH FLOWS**

The following summarizes our cash flows during the nine months ended September 30:

Cash Provided by (Used in)	2011	2010
	(Millions of Dollars)	
Operating Activities	\$ 474.4	\$ 362.8
Investing Activities	\$ (564.0)	\$ (297.8)
Financing Activities	\$ 79.4	\$ (72.6)

**Operating Activities**

Cash provided by operating activities was \$474.4 million during the nine months ended September 30, 2011 as compared to \$362.8 million during the nine months ended September 30, 2010. The largest increases in cash provided by operating activities related to higher net income, higher deferred income tax benefits and the

elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled \$421.3 million during the first nine months of 2011 as compared to \$65.4 million during the first nine months of 2010. We expect this trend to continue through the end of 2011. The largest reduction in cash provided by operating activities related to our contributions to our qualified benefit plans. During the first nine months of 2011, we contributed \$242.1 million to our qualified benefit plans. We made no contributions to the qualified plans during the first nine months of 2010.

### **Investing Activities**

Cash used in investing activities was \$564.0 million during the nine months ended September 30, 2011, which was \$266.2 million higher than the same period in 2010. This increase in cash used primarily reflects changes in restricted cash and increased capital expenditures. During the first nine months of 2011, our restricted cash increased primarily because of the nuclear fuel settlement we received from the DOE. During the same period in 2010, there was a decrease due to the release of restricted cash related to the Point Beach bill credits. See Nuclear Operations in this report for additional information regarding the settlement with the DOE. In addition, capital expenditures increased by approximately \$125.4 million during the first nine months of 2011 as compared to the first nine months of 2010 primarily due to increased spending related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park in 2011 as compared to 2010.

### **Financing Activities**

Cash provided by financing activities was \$79.4 million during the nine months ended September 30, 2011 as compared to cash used in financing activities of \$72.6 million during the same period in 2010. This change is primarily due to changes in our debt levels. During the first nine months of 2011, we issued \$300 million of long-term debt and used the net proceeds to repay short-term debt and for other general corporate purposes. Partially offsetting the increase in long-term debt, in 2010 we received a \$100 million capital contribution from Wisconsin Energy. We received no such capital contribution in 2011. For additional information on changes in our long-term debt, see Note 4 -- Long-Term Debt and Capital Lease Obligations in the Notes to Consolidated Condensed Financial Statements.

## **CAPITAL RESOURCES AND REQUIREMENTS**

### **Liquidity**

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

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

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

As of September 30, 2011, we had approximately \$494.1 million of available, undrawn lines under our bank back-up credit facility, and approximately \$121.0 million of commercial paper outstanding that was supported by the available lines of credit. During the first nine months of 2011, our maximum commercial paper outstanding was \$314.0 million with a weighted-average interest rate of 0.21%.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facility as of September 30, 2011:

<u>Total Facility</u>	<u>Letters of Credit</u>	<u>Credit Available</u>	<u>Facility Expiration</u>
(Millions of Dollars)			
\$ 500.0	\$ 5.9	\$ 494.1	December 2013

We recorded an increase of approximately \$650 million to our capital lease obligation in connection with OC 2 being placed into service in January 2011. For additional information, see Note 4 -- Long-Term Debt and Capital Lease Obligations in the Notes to Consolidated Condensed Financial Statements in this report.

We are the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of \$147 million. In August 2009, we terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. We issued commercial paper to fund the purchase of the bonds. As of September 30, 2011, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by us. Depending on market conditions and other factors, we may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

### Credit Rating Risk

Access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, security ratings reflect the views of the rating agencies only. An explanation of the significance of the ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

See Capital Resources and Requirements -- Credit Rating Risk in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2010 Annual Report on Form 10-K for additional information related to our credit rating risk.

### Capital Requirements

**Capital Expenditures:** Capital requirements during the remainder of 2011 are expected to be principally for capital expenditures relating to our electric distribution system and environmental controls at our Oak Creek generating units. Our 2011 capital expenditure estimate is approximately \$775 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 \$27.2 billion as of September 30, 2011 compared with \$24.6 billion as of December 31, 2010. Our total contractual obligations and other commercial commitments as of September 30, 2011 increased compared with December 31, 2010 primarily due to increased capital lease obligations related to OC 2, which was placed into service in January 2011, and long-term debt issued in September 2011.

## 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 2010 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, Wisconsin Energy's PTF strategy, rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

### POWER THE FUTURE

OC 2 was placed into service on January 12, 2011. All of the PTF units are now in service and are positioned to provide a significant portion of our future generation needs. We are leasing the units from We Power under long-term leases. We are recovering the lease payments associated with Port Washington Generating Station 1, Port Washington Generating Station 2 and Oak Creek expansion Unit 1 in our rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. We are recovering the lease payment associated with OC 2 as authorized by the PSCW and FERC, and have requested authorization from the MPSC in the rate case filed in July 2011. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2010 Annual Report on Form 10-K for additional information on PTF.

### RATES AND REGULATORY MATTERS

**2012 Wisconsin Rate Case:** On May 26, 2011, we filed an application with the PSCW to initiate rate proceedings. In lieu of a traditional rate proceeding, we requested an alternative approach, which results in no increase in 2012 base rates for our customers. In 2012, we would seek base rate increases to be effective in 2013. In order for us to proceed under this alternative approach, we requested that the PSCW issue an order that:

- Authorizes us to suspend the amortization of \$148 million of regulatory costs during 2012, with amortization to begin again in 2013.
- Authorizes \$148 million of carrying costs and depreciation on previously authorized air quality and renewable energy projects, effective January 1, 2012.
- Authorizes the refund of \$26 million of net proceeds from our settlement of the spent nuclear fuel litigation with the DOE.
- Authorizes us to reopen the rate proceeding in 2012 to address, for rates effective in 2013, all issues set aside during 2012, including the determination of the final approved construction costs for the Oak Creek expansion.
- Schedules a proceeding to establish a 2012 fuel cost plan.

On October 6, 2011, the PSCW approved our proposal as filed. We are waiting for a final written order from the PSCW. For information related to the proceeding to establish a 2012 fuel cost plan, see 2012 Fuel Recovery Request below.

**2012 Michigan Rate Case:** On July 5, 2011, we filed a \$17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. Therefore, we expect to self-implement \$7.7 million of the rate increase request effective in January 2012. A final decision from the MPSC is expected in July 2012.

**2012 Fuel Recovery Request:** On August 3, 2011, we filed a \$50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase are projected higher coal, coal transportation and nuclear purchased power costs. The impact of this filing is expected to be partially offset by a refund of approximately \$26 million to electric customers from a settlement reached earlier this year with the DOE regarding the storage of spent nuclear fuel. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. We expect new fuel rates to be implemented in January 2012.

**2010 Wisconsin Rate Case:** As part of its final decision in the 2010 rate case, the PSCW authorized us to reopen the docket in 2010 to review updated 2011 fuel costs. On September 3, 2010, we filed an application with the PSCW to reopen the docket to review updated 2011 fuel costs and to set rates for 2011 that reflect those costs. We

requested an increase in 2011 Wisconsin retail electric rates of \$38.4 million, or 1.4%, related to the increase in 2011 monitored fuel costs as compared to the level of monitored fuel costs then embedded in rates. In December 2010, we reduced our request by approximately \$5.2 million. Adjustments by the PSCW reduced the request by an additional \$7.8 million. The PSCW issued its final decision, which increased annual Wisconsin retail rates by \$25.4 million effective April 29, 2011. The net increase is being driven primarily by an increase in the delivered cost of coal.

**2010 Fuel Recovery Request:** In February 2010, we filed a \$60.5 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel and purchased power costs was driven primarily by increases in the price of natural gas compared to the forecasted prices included in the 2010 PSCW rate case order, changes in the timing of plant outages and increased MISO costs. Effective March 25, 2010, the PSCW approved an annual increase of \$60.5 million in Wisconsin retail electric rates on an interim basis. On April 28, 2011, the PSCW approved the final increase with no changes.

**Wisconsin Fuel Rules:** Embedded within our base rates is an amount to recover fuel costs. New fuel rules adopted in December 2010 require the company to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the utility's approved fuel cost plan. Fuel cost plans approved by the PSCW after January 1, 2011 are subject to the new rules.

**Renewable Energy Portfolio:** In September 2009, we announced plans to construct a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. We believe the biomass plant will be eligible for the federal production tax credit. In March 2010, we filed a request for a Certificate of Authority for the project with the PSCW. At its April 28, 2011 open meeting, the PSCW expressed concern about the overall cost of the project for our electric customers and directed the Company and Domtar to propose a lower cost structure for electric customers. The Company and Domtar submitted a joint response on May 3, 2011. On May 12, 2011, the PSCW issued its final decision approving the project and construction commenced on June 27, 2011. We currently expect to invest between \$245 and \$255 million, excluding AFUDC, in the plant and for it to be completed during the fall of 2013.

We have received all of the permits necessary to construct the biomass facility. In April 2011, opponents of the project filed a request for a contested case hearing related to the air pollution control construction permit issued by the WDNR. The WDNR denied the request in May 2011 because it was improperly filed. In June 2011, the opponents filed a petition for judicial review with the Marathon County Circuit Court seeking review of the WDNR's decision to deny the request for a contested case hearing. The court dismissed the case in September 2011. The opponents have 90 days from the date of the order (October 10, 2011) to appeal this decision.

**Edgewater Generating Unit 5:** On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to WPL for our net book value, including working capital, of approximately \$38 million.

See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7 of our 2010 Annual Report on Form 10-K for additional information regarding our rates and other regulatory matters.

## ELECTRIC TRANSMISSION AND ENERGY MARKETS

**MISO:** As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the Locational Marginal Pricing (LMP) system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through Auction Revenue Rights (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, 2011 through May 31, 2012. The resulting ARR valuation and the secured FTRs should mitigate our transmission congestion risk for that period.

## ENVIRONMENTAL MATTERS

As discussed in our 2010 Form 10-K and below, there are a significant number of regulations addressing the environment, including air quality and water quality. We believe that our cost to comply with these regulations will be

less than many other comparable utilities because of the investments that we have made in pollution control equipment and technology at our older coal generation units at our Pleasant Prairie and Oak Creek Power Plants, as well as the new pollution control equipment and technology installed at the new natural gas-fired generation units at Port Washington and the new coal-fired generation units at the Oak Creek expansion. Below is a discussion of some of the more significant environmental regulations that we are facing.

**8-hour Ozone Standard:** In March 2008, the United States Environmental Protection Agency (EPA) announced its decision to further lower the 8-hour ozone standard, and in January 2010, the EPA proposed to lower that standard further. In a December 2010 motion, the EPA asked that the litigation challenging the 2008 ozone National Ambient Air Quality Standards (NAAQS) be set aside. The EPA had indicated that it expected to complete its reconsideration rulemaking by July 29, 2011. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard until 2013.

**Sulfur Dioxide Standard:** In June 2010, the EPA issued new hourly Sulfur Dioxide (SO<sub>2</sub>) NAAQS that became effective in August 2010. These standards, as modified, represent a significant change from the previous SO<sub>2</sub> standards. The new standards, among other things, require attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations are based on monitored data.

Various parties petitioned the EPA for reconsideration of the SO<sub>2</sub> standards due to the changes to the implementation plan contained in the final rulemaking. The EPA denied these petitions because it claimed that its implementation plan was not part of the actual rule. Litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging both the stringency of the standards and EPA plans to require attainment designations to be based on modeling, as well as revisions to the state infrastructure state implementation plans.

If the new standards remain in place, we believe that we would not need to make significant capital expenditures at the majority of our generation units because of prior investments in pollution control equipment and technology. However, we believe that the new standards may require us to retire our Presque Isle Power Plant in the Upper Peninsula of Michigan early because the cost of installing new pollution control equipment at this plant may exceed other alternatives, such as investing in the transmission system in that region. The new standards may also require us to make modifications at some of our smaller generation units.

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

In December 2008, a number of environmental groups filed a complaint with the D.C. Circuit asking that the court place the EPA on a schedule for promulgating Maximum Achievable Control Technology (MACT) limits for fossil-fuel fired electric generating units to address hazardous air pollutants, including mercury. In October 2009, the EPA published notice of a proposed consent decree in connection with this litigation that would place the EPA on a schedule to set a MACT rule for coal and oil-fired electric generating units in 2011. In April 2010, the D.C. District Court approved a settlement agreement between the EPA and the plaintiffs in the litigation setting a firm schedule for the remanded rule-making. In accordance with this settlement, the EPA issued a proposed rule on March 16, 2011, and is required to issue the final rule by November 16, 2011. The proposed MACT rule is intended to reduce emissions of numerous hazardous air pollutants, including mercury. We are evaluating the potential impact of the proposed rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with such rule. Based upon our review, the Valley and Presque Isle power plants may require additional modifications. In addition, we believe that our clean air strategy, including the environmental upgrades that have already been constructed and that are currently under construction at our other plants, positions those plants well to meet the proposed requirements.

**Cross-State Air Pollution Rule:** On August 8, 2011, the EPA issued a final rule, the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule had been proposed in 2010 to replace the Clean Air Interstate Rule, which had been invalidated and remanded to the EPA in 2008.

The stated purpose of the CSAPR is to limit the interstate transport of emissions of nitrogen oxides and sulfur dioxide that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation scheme. The rule is scheduled to become effective on January 1, 2012, with further reductions required beginning in 2014. On October 5, 2011, we filed a petition for judicial review of the rule as it relates to the Presque

Isle Power Plant in Michigan. In addition, on October 6, 2011, we petitioned the EPA for reconsideration of certain provisions of CSAPR as they relate to our Presque Isle Power Plant. We have requested that the EPA grant an administrative stay of the rule and intend to seek a judicial stay of certain provisions of the rule that could adversely impact the Presque Isle Power Plant. The Presque Isle Power Plant was not allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation puts the plant at risk for certain penalties under the rule and, for this reason, we are seeking reconsideration of the rule. On October 6, 2011, the EPA announced proposed revisions to CSAPR, which we are currently reviewing. Although we believe the previous installation of controls on our generation fleet will help us meet the requirements of CSAPR, we are still evaluating this rule and its impact on our operations. However, based upon our preliminary analysis, we currently believe that we will have excess allowances which may be sold. We believe the net proceeds, if any, from the sale of excess allowances would be used to reduce fuel and purchased power costs under the Wisconsin Fuel Rules. There is a great deal of uncertainty in the undeveloped CSAPR allowance trading market due to pricing and early market volatility, which makes it difficult to determine our cost to comply with the new rule or the benefits that our customers may receive from the sale of excess allowances.

**Clean Water Act:** Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The EPA finalized rules for new facilities (Phase I) in 2001. Final rules for cooling water intake systems at existing facilities (Phase II) were promulgated in 2004. However, as a result of ongoing litigation, the EPA withdrew the Phase II rule in July 2007 and advised states to use their best professional judgment in making BTA decisions while the rule remains suspended.

The EPA has been in the process of revising the Phase II rules since mid-2007. In December 2010, the EPA and Riverkeeper Inc. (plaintiff in the litigation) set a firm schedule for the remanded Section 316(b) Phase II rulemaking. In accordance with the settlement agreement, the EPA proposed a new Phase II rule on March 28, 2011. The settlement requires a final rule by July 27, 2012. Once the rule is final, it will apply to all of our existing generating facilities with cooling water intake structures other than the Oak Creek expansion, which was permitted under the Phase I rules.

The proposed rule would create an impingement mortality reduction standard for all existing facilities. One proposed approach would allow a facility owner to satisfy the BTA requirement with respect to impingement mortality reduction if it demonstrates that its cooling water intake system has a maximum intake velocity of no more than 0.5 feet per second. Oak Creek Power Plant Units 5-8, Pleasant Prairie and Port Washington Generating Station all employ technologies that have a cooling water intake withdrawal velocity of less than 0.5 feet per second. We are still evaluating impingement mortality reduction compliance options for the Presque Isle and Valley power plants.

The EPA has proposed that the BTA for entrainment mortality reduction be determined on a case-by-case basis. Therefore, site-specific analysis would be required to determine BTA with respect to entrainment. The proposed rule allows permitting authorities to determine BTA controls on a site-specific basis following the consideration of several factors, including the cost of control technologies, the non-water quality impacts of control technologies, the monetary and non-monetary benefits of control technologies, land availability, and remaining useful plant life. Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet this proposed requirement.

The proposed rule is subject to public comment. Depending on the final requirements of the Phase II rule, we may need to modify the cooling water intake systems at some of our facilities. However, we are not able to make a determination until after the Phase II rule is final.

**Steam Electric Effluent Guidelines:** The federal Steam Electric Effluent guidelines, which regulate waste water discharges, are under review by the EPA. These rules govern discharges of waste water from our power plant processes. The EPA rules are expected to be finalized in the 2013-2014 timeframe. After the promulgation of final rules, it is expected that the WDNR will need to modify Wisconsin's rules. The existing Wisconsin state rules for waste water discharge are very stringent, and the systems that have been installed at the Pleasant Prairie Power Plant and the Oak Creek Power Plant use advanced technology. We are unable to determine the impact, if any, of these rules on our facilities at this time.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2010 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

## LEGAL MATTERS

**Cash Balance Pension Plan:** In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff has sought class certification for other similarly situated plaintiffs. The complaint alleges that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA and are owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant. The plaintiff has not specified the amount of relief he is seeking.

In March 2011, after the matter was addressed by the Plan's Employee Benefits Committee and following the Committee's review and analysis of the facts and evolving state of the law, the Plan acknowledged in an amended answer that it had used an incorrect interest crediting rate in computing lump sum payments prior to normal retirement age. The Committee determined the interest crediting rates that should be applied to address the interest crediting rate calculation and determined that the benefits for certain eligible participants should be recalculated. The plaintiff is opposing the Committee's actions and the Court has not yet decided what deference, if any, to give to the Committee's decision. In the meantime, the parties have engaged in mediation and are exploring settlement opportunities. We are currently unable to predict the final outcome or impact of this litigation. While an adverse outcome of this lawsuit could have a material adverse effect on Plan funding and future expense, we do not believe that the resolution of this matter will cost more than \$20 million in 2011.

**Stray Voltage:** In recent years, dairy farmers have commenced actions or made claims against us for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of our electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. The Wisconsin Supreme Court has rejected the arguments that, if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court has held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation. As a result of these rulings, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW "level of concern." In December 2008, a stray voltage lawsuit was filed against us. This lawsuit was settled in May 2011. This settlement did not have a material adverse effect on our financial condition or results of operations. Another stray voltage lawsuit was filed against us on January 27, 2011. We do not believe this lawsuit has merit and we will vigorously defend it. This lawsuit is not expected to have a material adverse effect on our financial statements. We continue to evaluate various options and strategies to mitigate this risk.

## NUCLEAR OPERATIONS

**Used Nuclear Fuel Storage and Disposal:** The Nuclear Waste Policy Act established the Nuclear Waste Fund, which is composed of payments made by the generators and owners of nuclear plants. We owned Point Beach through September 2007 and placed approximately \$215.2 million into this fund. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach. We filed a complaint in November 2000 against the DOE in the Court of Federal Claims for failure to begin performance. In December 2009, the Court ruled in our favor, granting us more than \$50 million in damages. In February 2010, the DOE filed an appeal. During the fourth quarter of 2010, we negotiated a settlement with the DOE for \$45.5 million, which we received in the first quarter of 2011. We anticipate that this amount, net of costs incurred, will be returned to customers.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2010. For information concerning market risk exposures at Wisconsin Electric Power Company, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 2010 Annual Report on Form 10-K.

## ITEM 4. CONTROLS AND PROCEDURES

**Disclosure Controls and Procedures:** Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal 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 principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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

## PART II -- OTHER INFORMATION

### ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2010 Annual Report on Form 10-K.

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

### RATES AND REGULATORY MATTERS

See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where we do business.

### OTHER MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 2 of this report for information regarding a lawsuit filed against the Plan, as well as information concerning stray voltage litigation. The lawsuit involving the Plan was previously reported in Part II -- Other Information in our Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011.

### ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors presented in our Annual Report on Form 10-K for the year ended December 31, 2010. See Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

**ITEM 6. EXHIBITS**Exhibit No.**4 Instruments defining the rights of security holders**

- 4.1 Securities Resolution No. 11 of Wisconsin Electric, dated as of September 7, 2011, under the Indenture for Debt Securities, dated as of December 1, 1995, between Wisconsin Electric and U.S. Bank National Association (as successor to Firststar Trust Company), as Trustee. (Exhibit 4.1 to Wisconsin Electric's 09/07/11 Form 8-K.)

**10 Material Contracts**

- 10.1 Letter Agreement by and between Wisconsin Energy and Joseph Kevin Fletcher, dated as of August 17, 2011, which became effective October 31, 2011. (Exhibit 10.1 to Wisconsin Energy's 09/30/11 Form 10-Q (File No. 001-09057).)

**31 Rule 13a-14(a) / 15d-14(a) Certifications**

- 31.1 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

**32 Section 1350 Certifications**

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

**101 Interactive Data File**

The following financial information from the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2011, formatted in Extensible Business Reporting Language ("XBRL"): (i) Consolidated Condensed Income Statements, (ii) Consolidated Condensed Balance Sheets, (iii) Consolidated Condensed Statements of Cash Flows and (iv) Notes to Consolidated Condensed Financial Statements.\*

- \* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not to be "filed" or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under these sections.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**WISCONSIN ELECTRIC POWER COMPANY**

(Registrant)

/s/STEPHEN P. DICKSON

Date: November 1, 2011

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