RAMBUS INC
Form 4
June 01, 2005

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
HOROWITZ MARK
(Last) (First) (Middle)
4440 EL CAMINO REAL
(Street)
LOS ALTOS, CA 94022
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
RAMBUS INC [RMBS]

3. Date of Earliest Transaction (Month/Day/Year)
06/01/2005

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	06/01/2005		S (1)		23,692	D	$ 15.4145	1,398,668	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
HOROWITZ MARK 4440 EL CAMINO REAL LOS ALTOS, CA 94022	X			

Signatures

By: Raquel Peasley For: Mark Horowitz	06/01/2005
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The sale reported in this Form 4 is effective pursuant to a Rule 10b5-1 trading plan adopted by the reporting person on August 29, 2003.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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- 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.

- The cyclical nature of property values that could affect our real estate investments.

- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Other business or investment considerations that may be disclosed from time to time in our 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.

Form 10-Q

INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company which conducts its operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our primary subsidiaries are Wisconsin Electric Power Company (Wisconsin Electric), Wisconsin Gas LLC (Wisconsin Gas) and W.E. Power, LLC (We Power).

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

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2010 Annual Report on Form 10-K for more information on PTF.

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

Form 10-Q

PART I -- FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$1,052.8	$973.2	$3,373.2	$3,112.7
Operating Expenses				
Fuel and purchased power	350.9	335.6	904.5	871.4
Cost of gas sold	69.2	67.4	533.4	519.0
Other operation and maintenance	296.9	318.1	909.3	971.0
Depreciation and amortization	82.6	77.4	246.2	228.6
Property and revenue taxes	28.9	26.9	85.5	79.8
Total Operating Expenses	828.5	825.4	2,678.9	2,669.8
Amortization of Gain	—	55.2	—	151.8
Operating Income	224.3	203.0	694.3	594.7
Equity in Earnings of Transmission Affiliate	15.7	15.2	46.4	45.5
Other Income, net	16.2	9.6	43.1	25.5
Interest Expense, net	56.8	52.5	177.6	154.9
Income from Continuing Operations Before Income Taxes	199.4	175.3	606.2	510.8
Income Taxes	69.6	63.0	207.5	182.0
Income from Continuing Operations	129.8	112.3	398.7	328.8
Income (Loss) from Discontinued Operations, Net of Tax	—	(0.1)	11.5	1.8
Net Income	$129.8	$112.2	$410.2	$330.6
Earnings Per Share (Basic)				
Continuing operations	$0.56	$0.48	$1.71	$1.41
Discontinued operations	—	—	0.05	—
Total Earnings Per Share (Basic)	$0.56	$0.48	$1.76	$1.41
Earnings Per Share (Diluted)				
Continuing operations	$0.55	$0.47	$1.69	$1.39
Discontinued operations	—	—	0.05	0.01
Total Earnings Per Share (Diluted)	$0.55	$0.47	$1.74	$1.40
Weighted Average Common Shares Outstanding (Millions)				

Basic	232.2	233.8	233.2	233.8
Diluted	234.9	236.9	236.0	236.7
Dividends Per Share of Common Stock	$0.26	$0.20	$0.78	$0.60

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

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WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	September 30, 2011	December 31, 2010
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$12,479.6	$11,590.8
Accumulated depreciation	(3,741.1)	(3,624.0)
	8,738.5	7,966.8
Construction work in progress	1,200.0	1,569.9
Leased facilities, net	60.6	64.8
Net Property, Plant and Equipment	9,999.1	9,601.5
Investments		
Equity investment in transmission affiliate	346.2	330.5
Other	36.6	45.8
Total Investments	382.8	376.3
Current Assets		
Cash and cash equivalents	15.1	24.5
Restricted cash	45.5	8.3
Accounts receivable, net	314.0	344.6
Accrued revenues	162.2	280.3
Materials, supplies and inventories	368.1	379.1
Prepayments and other	227.5	294.3
Total Current Assets	1,132.4	1,331.1
Deferred Charges and Other Assets		
Regulatory assets	1,082.9	1,090.1
Goodwill	441.9	441.9
Other	210.4	218.9
Total Deferred Charges and Other Assets	1,735.2	1,750.9
Total Assets	$13,249.5	$13,059.8
Capitalization and Liabilities		
Capitalization		
Common equity	$3,940.7	$3,802.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,618.9	3,932.0
Total Capitalization	8,590.0	7,764.5
Current Liabilities		
Long-term debt due currently	31.8	473.4
Short-term debt	496.7	657.9
Accounts payable	274.6	315.4
Other	286.3	274.4
Total Current Liabilities	1,089.4	1,721.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	918.0	883.8
Deferred income taxes - long-term	1,447.3	1,154.8
Deferred revenue, net	767.7	805.5
Pension and other benefit obligations	100.8	353.2

Other	336.3	376.9
Total Deferred Credits and Other Liabilities	3,570.1	3,574.2
Total Capitalization and Liabilities	$13,249.5	$13,059.8

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

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WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30			
	2011		2010	
	(Millions of Dollars)			
Operating Activities				
Net income	$410.2		$330.6	
Reconciliation to cash				
Depreciation and amortization	248.9		237.6	
Amortization of gain	—		(151.8	)
Equity in earnings of transmission affiliate	(46.4	)	(45.5	)
Distributions from transmission affiliate	37.0		37.0	
Deferred income taxes and investment tax credits, net	215.9		(1.0	)
Deferred revenue	2.9		78.0	
Contributions to qualified benefit plans	(257.4	)	—	
Change in - Accounts receivable and accrued revenues	136.4		111.4	
Inventories	11.1		(44.2	)
Other current assets	(18.7	)	37.8	
Accounts payable	(41.8	)	(39.8	)
Accrued income taxes, net	69.1		2.3	
Deferred costs, net	19.4		19.5	
Other current liabilities	27.1		51.0	
Other, net	13.9		30.8	
Cash Provided by Operating Activities	827.6		653.7	
Investing Activities				
Capital expenditures	(612.2	)	(545.6	)
Investment in transmission affiliate	(6.6	)	(3.9	)
Proceeds from asset sales	38.5		63.8	
Change in restricted cash	(37.2	)	131.8	
Other, net	(32.8	)	(56.1	)
Cash Used in Investing Activities	(650.3	)	(410.0	)
Financing Activities				
Exercise of stock options	34.4		76.0	
Purchase of common stock	(135.1	)	(128.5	)
Dividends paid on common stock	(182.0	)	(140.3	)
Issuance of long-term debt	720.0		530.0	
Retirement and repurchase of long-term debt	(464.7	)	(289.9	)
Change in short-term debt	(161.2	)	(306.5	)
Other, net	1.9		6.5	
Cash Used in Financing Activities	(186.7	)	(252.7	)
Change in Cash and Cash Equivalents	(9.4	)	(9.0	)
Cash and Cash Equivalents at Beginning of Period	24.5		20.2	

Cash and Cash Equivalents at End of Period	$15.1	$11.2

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

Form 10-Q

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(Unaudited)

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8, Financial Statements and Supplementary Data, in our 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.

Reclassifications: On January 20, 2011, our Board of Directors approved a two-for-one stock split of our common stock, which was effected through a stock dividend. New shares were distributed on March 1, 2011 to stockholders of record at the close of business on February 14, 2011. All share and per share information has been restated for all periods presented to reflect this stock split.

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 -- ACCOUNTING AND REPORTING FOR POWER THE FUTURE GENERATING UNITS

Background: As part of our PTF strategy, our non-utility subsidiary, We Power, built four new generating units, Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2), Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2), which are leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the Public Service Commission of Wisconsin (PSCW). The leases are designed to recover the capital costs of the plant, including a return. PWGS 1, PWGS 2, OC 1 and OC 2 were placed in service in July 2005, May 2008, February 2010 and January 2011, respectively. The accompanying consolidated condensed financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

The Oak Creek expansion includes common projects that benefit the existing units at this site as well as the new units. These projects include a coal handling facility and a water intake system, which were placed in service in November 2007 and January 2009, respectively.

During Construction: Under the terms of each lease, we collected in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for our PTF units. Our pre-tax cost of capital was approximately 14%. The carrying costs that we collected in rates were recorded as deferred revenue and are amortized to revenue over the term of each lease. During the construction of our PTF units, we capitalized interest costs at an overall weighted-average pre-tax cost of interest, which was approximately 5% for the nine months ended September 30, 2010. Capitalized interest is included in the total cost of the PTF units.

Plant in Service: Now that the PTF units are placed in service, we expect to continue to recover in rates the lease costs which reflect the authorized cash construction costs of the units plus a return on the investment. The authorized cash costs were established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs were recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first five years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return under each lease was established at rates determined in accordance with the terms of each lease.

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We recognize revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease.

4 -- COMMON EQUITY

Share-Based Compensation Expense: For a description of share-based compensation, including stock options, restricted stock and performance units, see Note I -- 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 outstanding stock options during the period other than necessary adjustments as a result of our stock split. Shares purchased on the open market by our independent agents are currently used to satisfy share-based awards.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Stock options	$0.6	$1.9	$1.9	$5.7
Performance units	7.3	10.3	11.7	20.9
Restricted stock	0.4	0.3	1.3	1.1
Share-based compensation expense	$8.3	$12.5	$14.9	$27.7
Related Tax Benefit	$3.4	$5.0	$6.0	$11.1

Stock Option Activity: During the first nine months of 2011, the Compensation Committee granted 458,180 non-qualified stock options that had an estimated fair value of $3.17 per share. During the first nine months of 2010, the Compensation Committee granted 549,500 stock options that had an estimated fair value of $3.36 per share. The following assumptions were used to value the 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 our historical experience.

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The following is a summary of our stock option activity for 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	11,925,226	$21.40		
Granted	—	$—		
Exercised	(272,412)	$17.82		
Forfeited	—	$—		
Outstanding as of September 30, 2011	11,652,814	$21.49		
Outstanding as of January 1, 2011	13,036,466	$20.81		
Granted	458,180	$29.35		
Exercised	(1,841,832)	$18.68		
Forfeited	—	$—		
Outstanding as of September 30, 2011	11,652,814	$21.49	5.5	$114.3
Exercisable as of September 30, 2011	8,499,304	$20.97	4.7	$87.7

The intrinsic value of options exercised was $3.6 million and $22.6 million for the three and nine months ended September 30, 2011, and $26.8 million and $51.9 million for the same periods in 2010, respectively. Cash received from options exercised was $34.4 million and $76.0 million for 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 $9.0 million and $20.2 million, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the third quarter of 2011.

The following table summarizes information about stock options outstanding as of September 30, 2011:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$11.33 to $17.10	2,405,276	$15.99	2.5	2,405,276	$15.99	2.5
$19.74 to $21.11	3,771,448	$20.61	6.2	1,569,748	$19.91	4.6
$23.88 to $29.35	5,476,090	$24.50	6.3	4,524,280	$23.98	5.8
	11,652,814	$21.49	5.5	8,499,304	$20.97	4.7

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The following table summarizes information about our non-vested 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	3,153,510	$3.78
Granted	—	$—
Vested	—	$—
Forfeited	—	$—
Non-vested as of September 30, 2011	3,153,510	$3.78
Non-vested as of January 1, 2011	5,272,570	$4.27
Granted	458,180	$3.17
Vested	(2,577,240)	$4.66
Forfeited	—	$—
Non-vested as of September 30, 2011	3,153,510	$3.78

As of September 30, 2011, total compensation costs related to non-vested stock options not yet recognized was approximately $1.3 million, which is expected to be recognized over the next 14 months on a weighted-average basis.

Restricted Shares: During the first nine months of 2011, the Compensation Committee granted 74,850 restricted shares to certain key employees and directors. These awards have a three-year vesting period, and generally, one-third of the award vests 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 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	198,820	
Granted	—	$—
Released	—	$—
Forfeited	—	$—
Outstanding as of September 30, 2011	198,820	
Outstanding as of January 1, 2011	205,404	
Granted	74,850	$29.00
Released	(78,624)	$19.03
Forfeited	(2,810)	$26.45
Outstanding as of September 30, 2011	198,820	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was zero and $2.3 million for the three and nine months ended September 30, 2011, and $0.1 million and $1.1 million for the same periods in 2010, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero and $0.7 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, respectively.

As of September 30, 2011, total compensation cost related to restricted stock not yet recognized was approximately $2.9 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

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Performance Units: In January 2011 and 2010, the Compensation Committee granted 435,690 and 555,830 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. 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 compensation costs over the three-year period based on our estimate of the final expected value of the awards. 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 $12.6 million and $9.8 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $4.3 million and $3.4 million, respectively. As of September 30, 2011, total compensation cost related to performance units not yet recognized was approximately $19.2 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note I -- 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.

Our total comprehensive income for the nine months ended September 30, 2011 and 2010 was $410.4 million and $330.9 million, respectively, which approximates net income for each of those periods.

Share Repurchase Program: We purchased 1.9 million shares of our common stock at a cost of $60.1 million and 4.9 million shares at a cost of $128.5 million for the nine months ended September 30, 2011 and 2010, respectively, to fulfill exercised stock options and restricted stock awards. In addition, on May 5, 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through September 30, 2011, we repurchased approximately 2.5 million shares pursuant to this program at an average cost of $30.32 per share and a total cost of $75.0 million.

5 -- DISCONTINUED OPERATIONS AND DIVESTITURES

The following table summarizes the net impacts of the discontinued operations on our earnings for the three and nine months ended September 30:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
	(Millions of Dollars)			

Income from Continuing Operations	$129.8	$112.3	$398.7	$328.8
Income from Discontinued Edison Sault operations, net of tax	—	—	—	1.8
Income (Loss) from Discontinued other operations, net of tax (a)	—	(0.1)	11.5	—
Net Income	$129.8	$112.2	$410.2	$330.6

(a) During 2011, we reached a favorable resolution of uncertain state and federal tax positions associated with our
previously discontinued manufacturing business.

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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.

Edison Sault: Effective May 4, 2010, we sold Edison Sault to Cloverland Electric Cooperative for approximately $63.0 million. We retained Edison Sault's ownership interest in ATC.

6 -- LONG-TERM DEBT

In September 2011, Wisconsin Electric 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.

In January 2011, we issued a total of $420 million in long-term debt ($205 million aggregate principal amount of 4.673% Series B Senior Notes due January 19, 2031 and $215 million aggregate principal amount of 5.848% Series B Senior Notes due January 19, 2041) and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. The Series B Senior Notes are secured by a collateral assignment of the leases between Elm Road Generating Station Supercritical, LLC (ERGSS) and Wisconsin Electric related to OC 2.

On April 1, 2011, we used cash and short-term borrowings to retire $450 million of long-term debt that matured.

7 -- FAIR VALUE MEASUREMENTS

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

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

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

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

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.

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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	3.9	10.1	14.5
Total	$46.0	$3.9	$10.1	$60.0
Liabilities:				
Derivatives	$9.6	$0.6	$—	$10.2
Total	$9.6	$0.6	$—	$10.2

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	5.3	5.9	15.7
Total	$12.8	$5.3	$5.9	$24.0
Liabilities:				
Derivatives	$6.1	$5.5	$—	$11.6
Total	$6.1	$5.5	$—	$11.6

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.

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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	$10.1	$10.4	$10.1	$10.4
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 8 -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

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

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	$4,543.3	$5,160.3	$4,288.0	$4,578.0

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

8 -- 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 and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

We record 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 $20.7 million in regulatory assets and $16.3 million in regulatory liabilities related to derivatives in comparison to $22.0 million in regulatory assets and $15.3 million in regulatory liabilities as of December 31, 2010.

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We record our current derivative assets on the balance sheet in Prepayments and other current assets and the current portion of the liabilities in Other current liabilities. We had no long-term portion of derivative assets as of September 30, 2011, and the long-term portion of our derivative liabilities of $0.5 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	$3.3	$10.2	$2.5	$11.6
Fuel Oil	0.5	—	4.4	—
FTRs	10.1	—	5.9	—
Coal	0.6	—	2.9	—
Total	$14.5	$10.2	$15.7	$11.6

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)		(Millions of Dollars)
Natural Gas	15.7 million Dth	$(10.5)	17.4 million Dth	$(8.8)
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		$(2.9)		$(5.0)

	Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	54.0 million Dth	$(27.7)	65.0 million Dth	$(33.3)
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		$(12.3)		$(17.7)

As of September 30, 2011 and December 31, 2010, we posted collateral of $12.8 million and $11.7 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in Prepayments and other current assets.

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9 -- 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:

	Pension Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
Benefit Plan Cost Components	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$4.0	$5.9	$11.9	$17.7
Interest cost	16.9	17.1	50.7	50.9
Expected return on plan assets	(20.5)	(19.6)	(61.6)	(58.3)
Amortization of:				
Prior service cost	0.6	0.6	1.7	1.7
Actuarial loss	8.4	6.7	25.5	20.0
Net Periodic Benefit Cost	$9.4	$10.7	$28.2	$32.0

	OPEB Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
Benefit Plan Cost Components	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.6	$2.8	$7.8	$8.4
Interest cost	5.2	5.3	15.6	15.8
Expected return on plan assets	(4.3)	(3.6)	(12.7)	(10.8)
Amortization of:				
Transition obligation	—	0.1	0.2	0.3
Prior service (credit)	(0.4)	(3.0)	(1.4)	(8.9)
Actuarial loss	1.7	2.7	4.7	8.1
Net Periodic Benefit Cost	$4.8	$4.3	$14.2	$12.9

In January 2011, we contributed $122.4 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 $13.5 million as of September 30, 2011 and $14.8 million as of December 31, 2010.

10 -- GUARANTEES

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

Maximum Potential

	Future Payments	Outstanding	Liability Recorded
	(Millions of Dollars)		
Guarantees	$2.8	$0.1	$—
Letters of Credit	$1.6	$0.7	$—

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

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

11 -- 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:

Three Months Ended	Operating Segments Energy Utility	Non-Utility	Corporate & Other (a) & Reconciling Items	Total Consolidated
	(Millions of Dollars)			
September 30, 2011				
Operating Revenues (b)	$1,036.7	$113.0	$(96.9)	$1,052.8
Depreciation and Amortization	$64.1	$18.3	$0.2	$82.6
Operating Income (Loss)	$135.6	$89.8	$(1.1)	$224.3
Equity in Earnings (Loss) of Unconsolidated Affiliates	$15.7	$—	$(0.1)	$15.6
Interest Expense, Net	$26.8	$16.9	$13.1	$56.8
Income Tax Expense (Benefit)	$45.5	$28.4	$(4.3)	$69.6
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—
Net Income (Loss)	$95.0	$44.6	$(9.8)	$129.8
Capital Expenditures	$252.1	$7.3	$5.7	$265.1
September 30, 2010				
Operating Revenues (b)	$960.5	$87.4	$(74.7)	$973.2
Depreciation and Amortization	$63.2	$13.9	$0.3	$77.4
Operating Income (Loss)	$134.2	$69.0	$(0.2)	$203.0
Equity in Earnings (Loss) of Unconsolidated Affiliates	$15.2	$—	$(0.1)	$15.1
Interest Expense, Net	$29.2	$11.0	$12.3	$52.5
Income Tax Expense (Benefit)	$44.6	$22.2	$(3.8)	$63.0
Income (Loss) from Discontinued Operations, Net of Tax	$—	$—	$(0.1)	$(0.1)
Net Income (Loss)	$84.7	$36.3	$(8.8)	$112.2
Capital Expenditures	$149.2	$16.6	$0.7	$166.5

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Nine Months Ended	Operating Segments Energy Utility	Non-Utility	Corporate & Other (a) & Reconciling Items	Total Consolidated
	(Millions of Dollars)			
September 30, 2011				
Operating Revenues (b)	$3,331.1	$327.5	$(285.4)	$3,373.2
Depreciation and Amortization	$191.4	$54.3	$0.5	$246.2
Operating Income (Loss)	$436.7	$261.7	$(4.1)	$694.3
Equity in Earnings (Loss) of Unconsolidated Affiliates	$46.4	$—	$(0.3)	$46.1
Interest Expense, Net	$82.1	$49.8	$45.7	$177.6
Income Tax Expense (Benefit)	$145.9	$84.2	$(22.6)	$207.5
Income from Discontinued Operations, Net of Tax	$—	$—	$11.5	$11.5
Net Income (Loss)	$297.1	$127.9	$(14.8)	$410.2
Capital Expenditures	$583.1	$22.2	$6.9	$612.2
Total Assets (c)	$12,847.8	$2,958.4	$(2,556.7)	$13,249.5
September 30, 2010				
Operating Revenues (b)	$3,083.9	$239.5	$(210.7)	$3,112.7
Depreciation and Amortization	$188.4	$39.5	$0.7	$228.6
Operating Income (Loss)	$410.1	$188.0	$(3.4)	$594.7
Equity in Earnings of Unconsolidated Affiliates	$45.5	$—	$—	$45.5
Interest Expense, Net	$88.9	$28.9	$37.1	$154.9
Income Tax Expense (Benefit)	$138.9	$62.7	$(19.6)	$182.0
Income from Discontinued Operations, Net of Tax	$0.7	$—	$1.1	$1.8
Net Income (Loss)	$252.9	$96.8	$(19.1)	$330.6
Capital Expenditures	$445.1	$99.0	$1.5	$545.6
Total Assets (c)	$11,700.2	$2,965.3	$(1,947.0)	$12,718.5

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

(b) An elimination for intersegment revenues of $97.2 million and $75.0 million for the three months ended September 30, 2011 and 2010, respectively, and $286.1 million and $211.2 million for the nine months ended September 30, 2011 and 2010, respectively, is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

(c) An elimination of $2,392.0 million and $1,803.3 million is included in Total Assets as of September 30, 2011 and 2010, respectively, for PTF-related activity between We Power and Wisconsin Electric.

12 -- VARIABLE INTEREST ENTITIES

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

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

We have identified two tolling and purchased power agreements with third parties 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

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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.

13 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters: We periodically review our exposure for remediation costs as evidence becomes available indicating that our liability has changed. Given current information, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial 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 manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal combustion product disposal/landfill sites used by Wisconsin Electric. 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 Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or 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 $35 million to $65 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 $45.1 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, 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.

Divestitures: Over the past several years, we have sold various businesses and assets. In connection with these sales, we have agreed to provide the respective buyers with customary indemnification provisions including, but not limited to, certain environmental, asbestos and product liability matters. In addition, pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit

5. We have established reserves as deemed appropriate for these indemnification provisions.

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 $0.05 per share in 2011.

Income Taxes: During 2011, our state and federal unrecognized tax benefits decreased by approximately $15.4 million exclusive of accrued interest, of which $10.2 million relates to discontinued operations. This decrease was the result of the expiration of state statute of limitations, as well as effective settlements with state and federal taxing authorities. Additionally, within the next 12 months, it is reasonably possible that our unrecognized tax benefits associated with discontinued operations may decrease by approximately $1.5 million due to the expiration of state statute of limitations.

14 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2011, we paid $138.1 million in interest, net of amounts capitalized, and received $62.7 million in net refunds from income taxes. During the nine months ended September 30, 2010, we paid $101.2 million in interest, net of amounts capitalized, and $162.0 million in income taxes, net of refunds.

As of September 30, 2011 and 2010, the amount of accounts payable related to capital expenditures was $19.2 million and $18.2 million, respectively.

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

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

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the third quarter of 2011 with the third quarter of 2010, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Utility Energy Segment	$135.6	$1.4	$134.2
Non-Utility Energy Segment	89.8	20.8	69.0
Corporate and Other	(1.1)	(0.9)	(0.2)
Total Operating Income	224.3	21.3	203.0
Equity in Earnings of Transmission Affiliate	15.7	0.5	15.2
Other Income, net	16.2	6.6	9.6
Interest Expense, net	56.8	(4.3)	52.5
Income from Continuing Operations Before Income Taxes	199.4	24.1	175.3
Income Taxes	69.6	(6.6)	63.0
Income from Continuing Operations	$129.8	$17.5	$112.3
Diluted Earnings Per Share from Continuing Operations	$0.55	$0.08	$0.47

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $135.6 million of operating income during the third quarter of 2011, an increase of $1.4 million, or 1.0%, compared with the third quarter of 2010. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended September 30		
Utility Energy Segment	2011	B (W)	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	$900.2	$73.0	$827.2
Gas	130.3	2.9	127.4
Other	6.2	0.3	5.9
Total Operating Revenues	1,036.7	76.2	960.5
Fuel and Purchased Power	352.1	(15.3)	336.8
Cost of Gas Sold	69.2	(1.8)	67.4
Gross Margin	615.4	59.1	556.3
Other Operating Expenses			
Other Operation and Maintenance	387.0	0.5	387.5
Depreciation and Amortization	64.1	(0.9)	63.2
Property and Revenue Taxes	28.7	(2.1)	26.6

Total Operating Expenses	901.1	(19.6)	881.5
Amortization of Gain	—	(55.2)	55.2
Operating Income	$135.6	$1.4	$134.2

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Electric Utility Revenues and Sales

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

	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	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	$900.2	$73.0	$827.2	8,651.4	259.5	8,391.9
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 -- Utility 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 our 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.

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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 $2.9 million, or 2.3%.

	Three Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	$130.3	$2.9	$127.4
Cost of Gas Sold	69.2	(1.8)	67.4
Gross Margin	$61.1	$1.1	$60.0

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:

	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$38.2	$0.8	$37.4	48.3	3.3	45.0
Commercial/Industrial	10.3	0.2	10.1	33.3	1.3	32.0
Interruptible	0.3	(0.1)	0.4	2.3	(0.9)	3.2
Total Retail	48.8	0.9	47.9	83.9	3.7	80.2
Transported Gas	11.1	(0.1)	11.2	200.3	(27.3)	227.6
Other	1.2	0.3	0.9	—	—	—
Total	$61.1	$1.1	$60.0	284.2	(23.6)	307.8
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 $1.1 million, or approximately 1.8%, when compared to the third quarter of 2010.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $0.5 million, or approximately 0.1%, when compared to the third quarter of 2010.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $0.9 million, or approximately 1.4%, 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

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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.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (PWGS 1, PWGS 2, OC 1 and OC 2). PWGS 1 and PWGS 2 were placed in service in July 2005 and May 2008, respectively. The common facilities associated with the Oak Creek expansion include the water intake system, which was placed in service in January 2009, the coal handling system, which was placed in service in November 2007, and other smaller assets. OC 1 and OC 2 were placed in service in February 2010 and January 2011, respectively.

The table below reflects a full quarter's earnings in 2011 and 2010 for PWGS 1, PWGS 2, OC 1 and the common facilities for the Oak Creek expansion. It also reflects a full quarter's earnings in 2011 for OC 2. This segment reflects the lease revenues on the new units as well as the depreciation expense. The operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Three Months Ended September 30, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$26.0	$80.3	$6.7	$113.0
Operation and Maintenance Expense	0.1	0.5	4.3	4.9
Depreciation Expense	4.9	12.9	0.5	18.3
Operating Income	$21.0	$66.9	$1.9	$89.8

	Three Months Ended September 30, 2010			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$26.1	$54.0	$7.3	$87.4
Operation and Maintenance Expense	0.2	0.6	3.7	4.5
Depreciation Expense	4.9	8.6	0.4	13.9
Operating Income	$21.0	$44.8	$3.2	$69.0

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended September 30		
Other Income, net	2011	B (W)	2010
	(Millions of Dollars)		
AFUDC - Equity	$16.0	$7.2	$8.8
Other	0.2	(0.6)	0.8
Other Income, net	$16.2	$6.6	$9.6

Other income, net increased by $6.6 million, or approximately 68.8%, 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.

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CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Three Months Ended September 30 2011	B (W)	2010
	(Millions of Dollars)		
Gross Interest Costs	$63.7	$1.9	$65.6
Less: Capitalized Interest	6.9	(6.2)	13.1
Interest Expense, net	$56.8	$(4.3)	$52.5

Our gross interest costs decreased by $1.9 million, or 2.9%, during the third quarter of 2011, primarily because of a reduction in our long-term debt weighted-average interest rate compared to the same period in 2010. Our capitalized interest decreased by $6.2 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by $4.3 million, or 8.2%, as compared to the third quarter of 2010.

CONSOLIDATED INCOME TAXES

For the third quarter of 2011, our effective tax rate applicable to continuing operations was 34.9% compared to 35.9% for the third quarter of 2010. For additional information, see Note H -- Income Taxes in our 2010 Annual Report on Form 10-K.

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

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first nine months of 2011 with the first nine months of 2010, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Nine Months Ended September 30 2011	B (W)	2010
	(Millions of Dollars)		
Utility Energy Segment	$436.7	$26.6	$410.1
Non-Utility Energy Segment	261.7	73.7	188.0
Corporate and Other	(4.1)	(0.7)	(3.4)
Total Operating Income	694.3	99.6	594.7
Equity in Earnings of Transmission Affiliate	46.4	0.9	45.5
Other Income, net	43.1	17.6	25.5
Interest Expense, net	177.6	(22.7)	154.9
Income from Continuing Operations Before Income Taxes	606.2	95.4	510.8
Income Taxes	207.5	(25.5)	182.0
Income from Continuing Operations	$398.7	$69.9	$328.8
Diluted Earnings Per Share from Continuing Operations	$1.69	$0.30	$1.39
Diluted Earnings Per Share from Discontinued Operations	$0.05	$0.04	$0.01

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $436.7 million of operating income during the first nine months of 2011, an increase of $26.6 million, or 6.5%, compared with the first nine months of 2010. The following table summarizes the operating income of this segment between the comparative periods:

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Utility Energy Segment	Nine Months Ended September 30 2011	B (W)	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,439.4	$206.7	$2,232.7
Gas	862.8	39.1	823.7
Other	28.9	1.4	27.5
Total Operating Revenues	3,331.1	247.2	3,083.9
Fuel and Purchased Power	908.1	(33.1)	875.0
Cost of Gas Sold	533.4	(14.4)	519.0
Gross Margin	1,889.6	199.7	1,689.9
Other Operating Expenses			
Other Operation and Maintenance	1,176.7	(12.6)	1,164.1
Depreciation and Amortization	191.4	(3.0)	188.4
Property and Revenue Taxes	84.8	(5.7)	79.1
Total Operating Expenses	2,894.4	(68.8)	2,825.6
Amortization of Gain	—	(151.8)	151.8
Operating Income	$436.7	$26.6	$410.1

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:

	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	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	2,246.9	175.3	2,071.6	20,718.3	(12.1)	20,730.4
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	$2,439.4	$206.7	$2,232.7	23,742.7	569.6	23,173.1
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 -- Utility Rates and Regulatory Matters.
- Unfavorable weather as compared to the prior year that decreased electric revenues by an estimated $27.0 million.

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- A $19.4 million increase in revenue from energy sold into the MISO energy market, which was driven by increased MWh generation from our 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 $39.1 million, or 4.7%, primarily because of colder weather during 2011.

	Nine Months Ended September 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	$862.8	$39.1	$823.7
Cost of Gas Sold	533.4	(14.4)	519.0
Gross Margin	$329.4	$24.7	$304.7

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:

	Nine Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$211.0	$16.4	$194.6	556.0	71.1	484.9
Commercial/Industrial	72.8	8.1	64.7	327.2	44.4	282.8
Interruptible	1.4	(0.2)	1.6	11.8	(2.8)	14.6
Total Retail	285.2	24.3	260.9	895.0	112.7	782.3
Transported Gas	38.9	1.2	37.7	667.4	(34.7)	702.1
Other	5.3	(0.8)	6.1	—	—	—
Total	$329.4	$24.7	$304.7	1,562.4	78.0	1,484.4
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 $24.7 million, or 8.1%, when compared to the first nine months of 2010. We estimate that approximately $23.1 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.

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Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by $12.6 million, or approximately 1.1%, when compared to the first nine months of 2010, of which approximately $5.5 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 $3.0 million, or approximately 1.6%, 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.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The table below reflects nine months of earnings in 2011 and 2010 for PWGS 1, PWGS 2 and the common facilities for the Oak Creek expansion. It also reflects eight months of earnings in 2010 and nine months of earnings in 2011 for OC 1, and eight and a half months of earnings in 2011 for OC 2. This segment reflects the lease revenues on the new units as well as the depreciation expense. The operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Nine Months Ended September 30, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$78.5	$239.7	$9.3	$327.5
Operation and Maintenance Expense	0.7	3.6	7.2	11.5
Depreciation Expense	14.8	38.1	1.4	54.3
Operating Income	$63.0	$198.0	$0.7	$261.7

	Nine Months Ended September 30, 2010			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$78.6	$149.4	$11.5	$239.5
Operation and Maintenance Expense	0.8	4.0	7.2	12.0
Depreciation Expense	14.8	23.5	1.2	39.5
Operating Income	$63.0	$121.9	$3.1	$188.0

CONSOLIDATED OTHER INCOME, NET

Nine Months Ended September 30

Other Income, net	2011	B (W)	2010
	(Millions of Dollars)		
AFUDC - Equity	$41.6	$19.5	$22.1
Other	1.5	(1.9)	3.4
Other Income, net	$43.1	$17.6	$25.5

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Other income, net increased by $17.6 million, or approximately 69.0%, 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.

CONSOLIDATED INTEREST EXPENSE, NET

	Nine Months Ended September 30		
Interest Expense	2011	B (W)	2010
	(Millions of Dollars)		
Gross Interest Costs	$196.7	$(2.9)	$193.8
Less: Capitalized Interest	19.1	(19.8)	38.9
Interest Expense, net	$177.6	$(22.7)	$154.9

Our gross interest costs increased by $2.9 million, or 1.5%, during the first nine months of 2011, primarily because of higher average long-term debt balances compared to the same period in 2010. In January 2011, we issued $420 million of long-term debt and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. Partially offsetting this increase, in April 2011, we retired $450 million of long-term debt that matured. Our capitalized interest decreased by $19.8 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by $22.7 million, or 14.7%, as compared to the first nine months of 2010.

CONSOLIDATED INCOME TAXES

For the first nine months of 2011, our effective tax rate applicable to continuing operations was 34.2% compared to 35.6% for the first nine months of 2010. During the first nine months of 2011, our tax expense was reduced primarily due to higher AFUDC - Equity and the favorable resolution of uncertain tax positions. For additional information, see Note H -- Income Taxes in our 2010 Annual Report on Form 10-K. We expect our 2011 annual effective tax rate to be between 34% and 35%.

DISCONTINUED OPERATIONS

During 2011, we reached a favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

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

	2011	2010
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$827.6	$653.7
Investing Activities	$(650.3)	$(410.0)

Financing Activities	$(186.7)	$(252.7)

Operating Activities

Cash provided by operating activities was $827.6 million during the nine months ended September 30, 2011 as compared to $653.7 million during the nine months ended September 30, 2010. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, higher deferred income tax benefits and the elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled $875.0 million during the first nine months of 2011 as compared to $415.4 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 qualified benefit plans. During the first nine months of 2011, we contributed $257.4 million to our qualified benefit plans. We made no contributions to our qualified plans during the first nine months of 2010.

Investing Activities

Cash used in investing activities was $650.3 million during the nine months ended September 30, 2011, which was $240.3 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 $66.6 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 used in financing activities was $186.7 million during the nine months ended September 30, 2011, which was $66.0 million lower than the same period in 2010. During the first nine months of 2011, we increased our total debt by $94.1 million compared to a decrease of $66.4 million in our total debt during the first nine months of 2010. Partially offsetting the change in total debt, we paid $41.7 million more in cash dividends during the first nine months of 2011 as compared to the first nine months of 2010. In January 2011, our Board of Directors approved a 30.0% increase in the quarterly common stock dividend for 2011. For additional information on changes in our long-term debt, see Note 6 -- Long-Term Debt 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.

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

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

As of September 30, 2011, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $496.7 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first nine months of 2011, our maximum commercial paper outstanding was $717.3 million with a weighted-average interest rate of 0.25%.

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

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Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
	(Millions of Dollars)			
Wisconsin Energy	$450.0	$0.4	$449.6	December 2013
Wisconsin Electric	$500.0	$5.9	$494.1	December 2013
Wisconsin Gas	$300.0	$—	$300.0	December 2013

The following table shows our capitalization structure as of September 30, 2011, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated notes (Junior Notes):

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$3,940.7	$4,190.7
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,650.7	4,400.7
Short-Term Debt	496.7	496.7
Total Capitalization	$9,118.5	$9,118.5
Total Debt	$5,147.4	$4,897.4
Ratio of Debt to Total Capitalization	56.5 %	53.7 %

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of September 30, 2011 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric 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 Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

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.

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Capital Requirements

Capital Expenditures: Capital requirements during the remainder of 2011 are expected to be principally for capital expenditures in our utility operations relating to our electric distribution system and environmental controls at our Oak Creek generating units. Our 2011 consolidated capital expenditure estimate is approximately $900 million.

Common Stock Matters: On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through October 31, 2011, we have acquired approximately 2.5 million shares in open market purchases at a cost of $75.0 million pursuant to this program. For additional information regarding the share repurchases, see Part II, Item 2 - Unregistered Sales of Equity Securities and Use of Proceeds.

The Board of Directors adopted a new dividend policy for Wisconsin Energy starting in 2012. Pursuant to this new policy, we will target a dividend payout ratio that trends to 60% of earnings over the period from 2012 to 2015. In connection with this policy, management intends to recommend to Wisconsin Energy's Board of Directors a dividend increase of 13% to 15% for 2012.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We continue to believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note 10 -- Guarantees and Note 12 -- Variable Interest Entities in the Notes to Consolidated Condensed Financial Statements in this report.

Contractual Obligations/Commercial Commitments: Our total contractual obligations and other commercial commitments were approximately $21.5 billion as of September 30, 2011 compared with $21.1 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 long-term debt issued in January 2011 in connection with the commercial operation of OC 2 as well as long-term debt issued by Wisconsin Electric in September 2011, partially offset by long-term debt retired at its maturity in April 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, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

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 recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2 and OC 1 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. Wisconsin Electric is recovering the lease payments associated with OC 2 as authorized by the PSCW and FERC, and has 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.

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UTILITY RATES AND REGULATORY MATTERS

2012 Wisconsin Rate Case: On May 26, 2011, Wisconsin Electric and Wisconsin Gas 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, Wisconsin Electric and Wisconsin Gas would seek base rate increases to be effective in 2013. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that:

- Authorizes Wisconsin Electric 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 Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE.
- Authorizes Wisconsin Electric 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, Wisconsin Electric 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, Wisconsin Electric 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 Wisconsin Electric to reopen the docket in 2010 to review updated 2011 fuel costs. On September 3, 2010, Wisconsin Electric 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. Wisconsin Electric 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, Wisconsin Electric reduced its 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, Wisconsin Electric 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 Wisconsin Electric's 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.

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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 Wisconsin Electric and Domtar to propose a lower cost structure for electric customers. Wisconsin Electric 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 million 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 -- Utility Rates and Regulatory Matters in Item 7 of our 2010 Annual Report on Form 10-K for additional information regarding our utility 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 Price (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 our 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_2) NAAQS that became effective in August 2010. These standards, as modified, represent a significant change from the previous SO_2 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_2 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,

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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

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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 $0.05 per share in 2011.

Stray Voltage: In recent years, dairy farmers have commenced actions or made claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of its 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 Wisconsin Electric. 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 Wisconsin Electric 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. Wisconsin Electric 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. Wisconsin Electric 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 favor of Wisconsin Electric, 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 Energy Corporation, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 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.

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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.

UTILITY RATES AND REGULATORY MATTERS

See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where Wisconsin Electric and Wisconsin Gas 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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three months ended September 30, 2011:

ISSUER PURCHASES OF EQUITY SECURITIES

2011	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (a)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or

				Programs (Millions of Dollars)
July 1 - July 31	795,416	$31.34	795,416	$275.1
August 1 - August 31	1,676,446	$29.83	1,676,446	$225.1
September 1 - September 30	—	$—	—	$225.1
Total	2,471,862	$30.32	2,471,862	$—

(a) On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through December 31, 2013.

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ITEM 6. EXHIBITS

Exhibit No.	
4	Instruments defining the rights of security holders, including indentures
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 Firstar 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.
31	Rule 13a-14(a) / 15d-14(a) Certifications
31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certifications
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data File

SIGNATURES

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

	WISCONSIN ENERGY CORPORATION (Registrant)
Date: November 1, 2011	/s/STEPHEN P. DICKSON Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer