WISCONSIN ENERGY CORP
Form 10-Q
August 02, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2012

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

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

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

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2012):

Common Stock, $.01 Par Value, 230,447,077 shares outstanding.

Form 10-Q

WISCONSIN ENERGY CORPORATION

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FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 2012

TABLE OF CONTENTS

Item		Page
	Introduction	7
	Part I -- Financial Information	
1.	Financial Statements	
	Consolidated Condensed Income Statements	8
	Consolidated Condensed Balance Sheets	9
	Consolidated Condensed Statements of Cash Flows	10
	Notes to Consolidated Condensed Financial Statements	11
2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	24
3.	Quantitative and Qualitative Disclosures About Market Risk	40
4.	Controls and Procedures	41
	Part II -- Other Information	
1.	Legal Proceedings	41
1A.	Risk Factors	42
2.	Unregistered Sales of Equity Securities and Use of Proceeds	42
6.	Exhibits	43
	Signatures	44

Form 10-Q

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Primary Subsidiaries	
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
WECC	Wisconsin Energy Capital Corporation
Federal and State Regulatory Agencies	
DOE	United States Department of Energy
DOJ	Wisconsin Department of Justice
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
MACT	Maximum Achievable Control Technology
NOV	Notice of Violation
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Compensation Committee	Compensation Committee of the Board of Directors
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
Junior Notes	

Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007

Form 10-Q

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
NDAA	National Defense Authorization Act
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.
Measurements	
Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage
Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

Form 10-Q

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

- Factors affecting utility operations such as catastrophic weather-related or terrorism-related damage; cyber-security threats and disruptions to our technology network; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; unanticipated changes in the cost or availability of materials needed to operate new environmental controls at our electric generating facilities or replace and/or repair our electric and gas distribution systems; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

- Factors affecting the demand for electricity and natural gas, including weather and other natural phenomena; the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; and energy conservation efforts.

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with our Power the Future (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.

- Increased competition in our electric and gas markets and continued industry consolidation.

- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cybersecurity threats; required approvals for new construction, and the

siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

Form 10-Q

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

- Current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and Internal Revenue Service (IRS) audits and other tax matters.

- Events in the global credit markets that may affect the availability and cost of capital.

- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.

- The investment performance of our pension and other post-retirement benefit trusts.

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.

- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act and any regulations promulgated thereunder, including rules recently adopted and/or proposed by the U.S. Commodity Futures Trading Commission that may impact our hedging activities and related costs.

- 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 ability to obtain and retain short- and long-term contracts with wholesale customers.

- 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.

- Foreign governmental, economic, political and currency risks.

- 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, 2011.

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 reportable 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 1. Business and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 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 2011 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 June 30		Six Months Ended June 30	
	2012	2011	2012	2011
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$944.7	$991.7	$2,135.9	$2,320.4
Operating Expenses				
Fuel and purchased power	258.7	286.0	512.5	553.6
Cost of gas sold	75.0	121.8	312.5	464.2
Other operation and maintenance	267.9	298.9	554.2	612.4
Depreciation and amortization	90.3	82.3	177.9	163.6
Property and revenue taxes	30.2	28.3	60.5	56.6
Total Operating Expenses	722.1	817.3	1,617.6	1,850.4
Operating Income	222.6	174.4	518.3	470.0
Equity in Earnings of Transmission Affiliate	16.2	15.2	31.8	30.7
Other Income, net	8.6	14.4	24.6	26.9
Interest Expense, net	61.5	57.4	120.4	120.8
Income from Continuing Operations Before Income Taxes	185.9	146.6	454.3	406.8
Income Tax Expense	66.6	48.6	162.9	137.9
Income from Continuing Operations	119.3	98.0	291.4	268.9
Income from Discontinued Operations, Net of Tax	—	11.5	—	11.5
Net Income	$119.3	$109.5	$291.4	$280.4
Earnings Per Share (Basic)				
Continuing operations	$0.52	$0.42	$1.26	$1.15
Discontinued operations	—	0.05	—	0.05
Total Earnings Per Share (Basic)	$0.52	$0.47	$1.26	$1.20
Earnings Per Share (Diluted)				
Continuing operations	$0.51	$0.41	$1.25	$1.14
Discontinued operations	—	0.05	—	0.05
Total Earnings Per Share (Diluted)	$0.51	$0.46	$1.25	$1.19

Weighted Average Common Shares Outstanding (Millions)				
Basic	230.4	233.7	230.5	233.7
Diluted	233.1	236.6	233.1	236.6
Dividends Per Share of Common Stock	$0.30	$0.26	$0.60	$0.52

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

Form 10-Q

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2012	December 31, 2011
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$13,595.4	$12,977.7
Accumulated depreciation	(3,915.7)	(3,797.8)
	9,679.7	9,179.9
Construction work in progress	604.7	921.3
Leased facilities, net	56.3	59.2
Net Property, Plant and Equipment	10,340.7	10,160.4
Investments		
Equity investment in transmission affiliate	362.1	349.7
Other	37.6	43.6
Total Investments	399.7	393.3
Current Assets		
Cash and cash equivalents	13.1	14.1
Restricted cash	17.9	45.5
Accounts receivable, net	297.3	349.4
Accrued revenues	201.5	252.7
Materials, supplies and inventories	335.0	382.0
Prepayments and other	372.1	382.5
Total Current Assets	1,236.9	1,426.2
Deferred Charges and Other Assets		
Regulatory assets	1,287.6	1,238.7
Goodwill	441.9	441.9
Other	180.8	201.6
Total Deferred Charges and Other Assets	1,910.3	1,882.2
Total Assets	$13,887.6	$13,862.1
Capitalization and Liabilities		
Capitalization		
Common equity	$4,081.1	$3,963.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,297.5	4,614.3
Total Capitalization	8,409.0	8,608.0
Current Liabilities		
Long-term debt due currently	334.8	32.6
Short-term debt	559.5	669.9
Accounts payable	267.5	325.7
Accrued payroll and vacation	89.2	105.9
Other	177.4	230.4
Total Current Liabilities	1,428.4	1,364.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	906.2	902.0
Deferred income taxes - long-term	1,862.5	1,696.1

Deferred revenue, net	727.5	754.5
Pension and other benefit obligations	251.6	222.7
Other	302.4	314.3
Total Deferred Credits and Other Liabilities	4,050.2	3,889.6
Total Capitalization and Liabilities	$13,887.6	$13,862.1

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

Form 10-Q

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

	Six Months Ended June 30	
	2012	2011
	(Millions of Dollars)	
Operating Activities		
Net income	$291.4	$280.4
Reconciliation to cash		
Depreciation and amortization	183.8	169.2
Deferred income taxes and investment tax credits, net	141.2	137.0
Contributions to qualified benefit plans	—	(122.4)
Change in - Accounts receivable and accrued revenues	96.2	91.1
Inventories	47.0	40.0
Other current assets	16.7	10.2
Accounts payable	(60.2)	(38.7)
Accrued income taxes, net	5.7	59.2
Other current liabilities	(27.5)	11.4
Other, net	(85.6)	11.2
Cash Provided by Operating Activities	608.7	648.6
Investing Activities		
Capital expenditures	(314.0)	(347.1)
Investment in transmission affiliate	(6.6)	(4.6)
Proceeds from asset sales	2.8	38.5
Change in restricted cash	27.6	(37.2)
Other, net	(22.4)	(17.1)
Cash Used in Investing Activities	(312.6)	(367.5)
Financing Activities		
Exercise of stock options	38.6	29.6
Purchase of common stock	(77.0)	(51.6)
Dividends paid on common stock	(138.3)	(121.5)
Issuance of long-term debt	—	420.0
Retirement and repurchase of long-term debt	(10.0)	(456.9)
Change in short-term debt	(110.4)	(115.5)
Other, net	—	0.9
Cash Used in Financing Activities	(297.1)	(295.0)
Change in Cash and Cash Equivalents	(1.0)	(13.9)
Cash and Cash Equivalents at Beginning of Period	14.1	24.5
Cash and Cash Equivalents at End of Period	$13.1	$10.6

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 2011 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 six months ended June 30, 2012 are not necessarily indicative of the results which may be expected for the entire fiscal year 2012 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Presentation of Comprehensive Income: In June 2011, the Financial Accounting Standards Board (FASB) issued guidance on the presentation of comprehensive income. The guidance gives entities the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied retrospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

Fair Value Measurement: In May 2011, the FASB issued guidance amending existing guidance for measuring fair value and expanding required disclosures about fair value measurements. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied prospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

3 -- COMMON EQUITY

Stock Option Activity: During the first six months of 2012, the Compensation Committee granted 938,770 non-qualified stock options that had an estimated fair value of $3.34 per share. During the first six months of 2011, the Compensation Committee granted 458,180 non-qualified stock options that had an estimated fair value of $3.17 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2012	2011
Risk-free interest rate	0.1% - 2.0%	0.2% - 3.4%
Dividend yield	3.9%	3.9%
Expected volatility	19.0%	19.0%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	5.9	5.5

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.

Form 10-Q

The following is a summary of our stock option activity for the three and six months ended June 30, 2012:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2012	10,851,131	$23.03		
Granted	—	$—		
Exercised	(1,279,600)	$20.09		
Forfeited	—	$—		
Outstanding as of June 30, 2012	9,571,531	$23.42		
Outstanding as of January 1, 2012	10,638,750	$21.65		
Granted	938,770	$34.88		
Exercised	(1,998,269)	$19.34		
Forfeited	(7,720)	$26.94		
Outstanding as of June 30, 2012	9,571,531	$23.42	5.6	$154.5
Exercisable as of June 30, 2012	7,845,366	$21.76	4.9	$139.7

The intrinsic value of options exercised was $21.6 million and $33.6 million for the three and six months ended June 30, 2012, and $9.9 million and $19.0 million for the same periods in 2011, respectively. Cash received from options exercised was $38.6 million and $29.6 million for the six months ended June 30, 2012 and 2011, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was zero and approximately $7.5 million, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the second quarter and first six months of 2012.

The following table summarizes information about stock options outstanding as of June 30, 2012:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$12.71 to $19.74	2,188,544	$18.08	2.7	2,188,544	$18.08	2.7
$21.11 to $24.92	5,995,997	$23.14	5.8	5,541,467	$22.99	5.6
$29.35 to $34.88	1,386,990	$33.09	9.2	115,355	$32.60	9.1
	9,571,531	$23.42	5.6	7,845,366	$21.76	4.9

Form 10-Q

The following table summarizes information about our non-vested options during the three and six months ended June 30, 2012:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of April 1, 2012	1,732,770	$3.31
Granted	—	$—
Vested	(6,605)	$3.30
Forfeited	—	$—
Non-vested as of June 30, 2012	1,726,165	$3.31
Non-vested as of January 1, 2012	3,103,770	$3.78
Granted	938,770	$3.34
Vested	(2,308,655)	$3.96
Forfeited	(7,720)	$3.25
Non-vested as of June 30, 2012	1,726,165	$3.31

As of June 30, 2012, total compensation costs related to non-vested stock options not yet recognized was approximately $2.4 million, which is expected to be recognized over the next 18 months on a weighted-average basis.

Restricted Shares: During the first six months of 2012, the Compensation Committee granted 94,959 restricted shares to directors, officers and other key employees. 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 six months ended June 30, 2012:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of April 1, 2012	210,912	
Granted	—	$—
Released	(15,762)	$19.38
Forfeited	(453)	$31.02
Outstanding as of June 30, 2012	194,697	
Outstanding as of January 1, 2012	192,558	
Granted	94,959	$34.46
Released	(88,422)	$30.65
Forfeited	(4,398)	$30.83
Outstanding as of June 30, 2012	194,697	

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 $0.7 million and $3.3 million for the three and six months ended June 30, 2012, and $0.2 million and $2.3 million for the same periods in 2011, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero for the three and six months ended June 30, 2012, and $0.1 million and $0.7 million for the same periods in 2011, respectively.

As of June 30, 2012, total compensation cost related to restricted stock not yet recognized was approximately $3.9 million, which is expected to be recognized over the next 24 months on a weighted-average basis.

Form 10-Q

Performance Units: In January 2012 and 2011, the Compensation Committee granted 346,570 and 435,690 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, 2011 and 2010 vested and were settled during the first quarter of 2012 and 2011, and had a total intrinsic value of $26.7 million and $12.6 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $9.7 million and $4.3 million, respectively. As of June 30, 2012, total compensation cost related to performance units not yet recognized was approximately $29.1 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 2011 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.

There was no material other comprehensive income for the three and six months ended June 30, 2012 or 2011.

Share Repurchase Program: In May 2011, our Board of Directors authorized a share repurchase program that allows us to repurchase up to $300 million of our common stock through the end of 2013. Through June 30, 2012, we have repurchased $100.0 million of our common stock pursuant to this program at an average cost of $30.79 per share. The share 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. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company in the following periods:

	Six Months Ended June 30			
	2012		2011	
	Shares	Cost	Shares	Cost
	(In Millions)			
Under May 2011 share repurchase program	—	$—	—	$—
To fulfill exercised stock options and restricted stock awards	2.1	75.7	1.6	50.8
Total	2.1	$75.7	1.6	$50.8

Form 10-Q

4 -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

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

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
	(Millions of Dollars)			
Income from Continuing Operations	$119.3	$98.0	$291.4	$268.9
Income from Discontinued Operations, net of tax (a)	—	11.5	—	11.5
Net Income	$119.3	$109.5	$291.4	$280.4

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

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. (WPL) for our net book value, including working capital, of approximately $38 million. This transaction was treated as a sale of an asset.

5 -- LONG-TERM DEBT

In January 2011, we issued a total of $420 million of 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 Oak Creek expansion Unit 2 (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.

As of June 30, 2012, we were in compliance with all financial covenants.

6 -- FAIR VALUE MEASUREMENTS

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

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

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

Level 1 -- Pricing inputs are unadjusted quoted prices 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.

Form 10-Q

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

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

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

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

Recurring Fair Value Measures	As of June 30, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$17.9	$—	$—	$17.9
Derivatives	2.7	12.1	9.9	24.7
Total	$20.6	$12.1	$9.9	$42.6
Liabilities:				
Derivatives	$0.5	$7.5	$—	$8.0
Total	$0.5	$7.5	$—	$8.0

Recurring Fair Value Measures	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$45.5	$—	$—	$45.5
Derivatives	0.3	14.6	5.7	20.6
Total	$45.8	$14.6	$5.7	$66.1
Liabilities:				
Derivatives	$8.2	$1.0	$—	$9.2
Total	$8.2	$1.0	$—	$9.2

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which is being 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

Form 10-Q

in Level 3.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy:

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
	(Millions of Dollars)			
Beginning Balance	$2.2	$2.1	$5.7	$5.9
Realized and unrealized gains (losses)	—	—	—	—
Purchases	10.9	16.1	10.9	16.1
Issuances	—	—	—	—
Settlements	(3.2)	(3.6)	(6.7)	(7.4)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of June 30	$9.9	$14.6	$9.9	$14.6
Change in unrealized gains (losses) relating to instruments still held as of June 30	$—	$—	$—	$—

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

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

Financial Instruments	June 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$26.1	$30.4	$25.1
Long-term debt, including current portion	$4,531.4	$5,248.0	$4,541.4	$5,179.9

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases and unamortized discount 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. Based on these assessments, the above items have been classified within Level 2.

7 -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers 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 Public Service Commission of Wisconsin (PSCW).

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized

Form 10-Q

for derivatives executed with the same counterparty under the same master netting arrangement. As of June 30, 2012, we recognized $16.3 million in regulatory assets and $22.0 million in regulatory liabilities related to derivatives in comparison to $29.6 million in regulatory assets and $21.7 million in regulatory liabilities as of December 31, 2011.

We record our current derivative assets on the balance sheet in prepayments and other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.1 million is recorded in other deferred charges and other assets as of June 30, 2012, and the long-term portion of our derivative liabilities of $1.5 million is recorded in other deferred credits and other liabilities as of June 30, 2012. Our Consolidated Condensed Balance Sheets as of June 30, 2012 and December 31, 2011 include:

	June 30, 2012		December 31, 2011	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$5.0	$0.1	$2.1	$9.1
Fuel Oil	—	0.5	0.3	0.1
FTRs	9.9	—	5.7	—
Coal	9.8	7.4	12.5	—
Total	$24.7	$8.0	$20.6	$9.2

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) were as follows:

	Three Months Ended June 30, 2012		Three Months Ended June 30, 2011	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	18.5 million Dth	$(14.2)	18.9 million Dth	$(6.6)
Fuel Oil	2.1 million gallons	0.8	3.4 million gallons	2.1
FTRs	5,296 MW	1.6	6,191 MW	1.5
Total		$(11.8)		$(3.0)

	Six Months Ended June 30, 2012		Six Months Ended June 30, 2011	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	38.9 million Dth	$(30.4)	38.3 million Dth	$(17.2)
Fuel Oil	3.8 million gallons	1.4	6.6 million gallons	2.5
FTRs	10,654 MW	2.2	12,543 MW	5.3
Total		$(26.8)		$(9.4)

As of June 30, 2012 and December 31, 2011, we posted collateral of $7.9 million and $11.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

Form 10-Q

8 -- BENEFITS

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

	Pension Costs			
	Three Months Ended June 30		Six Months Ended June 30	
Benefit Plan Cost Components	2012	2011	2012	2011
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$5.4	$3.3	$10.8	$7.9
Interest cost	16.4	17.1	32.8	33.8
Expected return on plan assets	(22.2)	(20.4)	(44.8)	(41.1)
Amortization of:				
Prior service cost	0.6	0.5	1.2	1.1
Actuarial loss	10.3	9.0	20.2	17.1
Net Periodic Benefit Cost	$10.5	$9.5	$20.2	$18.8

	OPEB Costs			
	Three Months Ended June 30		Six Months Ended June 30	
Benefit Plan Cost Components	2012	2011	2012	2011
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.4	$2.4	$5.2	$5.2
Interest cost	5.1	5.1	10.2	10.4
Expected return on plan assets	(4.8)	(4.1)	(9.6)	(8.4)
Amortization of:				
Transition obligation	0.1	0.1	0.2	0.2
Prior service (credit)	(0.4)	(0.5)	(0.9)	(1.0)
Actuarial loss	1.7	1.5	3.5	3.0
Net Periodic Benefit Cost	$4.1	$4.5	$8.6	$9.4

During the first six months of 2011, we contributed $122.4 million to our qualified benefit plans. No such contributions were made during the first six months of 2012. 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 $5.2 million as of June 30, 2012 and $15.3 million as of December 31, 2011.

Form 10-Q

9 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable segments for the three and six months ended June 30, 2012 and 2011 is shown in the following table:

	Reportable Segments			Eliminations	
Three Months Ended	Energy Utility	Non-Utility	Corporate & Other (a)	& Reconciling Items	Total Consolidated
	(Millions of Dollars)				
June 30, 2012					
Operating Revenues (b)	$930.5	$112.3	$0.3	$(98.4)	$944.7
Other Operation and Maintenance	$358.5	$5.3	$1.4	$(97.3)	$267.9
Depreciation and Amortization	$73.4	$16.7	$0.2	$—	$90.3
Operating Income (Loss)	$133.6	$90.3	$(1.3)	$—	$222.6
Equity in Earnings of Unconsolidated Affiliates	$16.2	$—	$(0.1)	$—	$16.1
Interest Expense, Net	$32.0	$16.7	$12.9	$(0.1)	$61.5
Income Tax Expense (Benefit)	$43.0	$29.2	$(5.6)	$—	$66.6
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$82.7	$44.4	$119.3	$(127.1)	$119.3
Capital Expenditures	$169.4	$1.9	$0.4	$—	$171.7
June 30, 2011					
Operating Revenues (b)	$977.9	$111.3	$0.2	$(97.7)	$991.7
Other Operation and Maintenance	$388.8	$5.1	$1.7	$(96.7)	$298.9
Depreciation and Amortization	$63.9	$18.3	$0.1	$—	$82.3
Operating Income (Loss)	$88.1	$87.9	$(1.6)	$—	$174.4
Equity in Earnings of Unconsolidated Affiliates	$15.2	$—	$(0.1)	$—	$15.1
Interest Expense, Net	$27.2	$17.0	$13.3	$(0.1)	$57.4
Income Tax Expense (Benefit)	$29.1	$28.1	$(8.6)	$—	$48.6
Income from Discontinued Operations, Net of Tax	$—	$—	$11.5	$—	$11.5
Net Income (Loss)	$61.1	$42.8	$109.5	$(103.9)	$109.5
Capital Expenditures	$203.8	$6.7	$1.1	$—	$211.6

Form 10-Q

Six Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
June 30, 2012					
Operating Revenues (b)	$2,108.9	$219.6	$0.6	$(193.2)	$2,135.9
Other Operation and Maintenance	$734.9	$7.4	$2.7	$(190.8)	$554.2
Depreciation and Amortization	$144.1	$33.5	$0.3	$—	$177.9
Operating Income (Loss)	$342.2	$178.7	$(2.6)	$—	$518.3
Equity in Earnings of Unconsolidated Affiliates	$31.8	$—	$(0.1)	$—	$31.7
Interest Expense, Net	$61.2	$33.5	$26.0	$(0.3)	$120.4
Income Tax Expense (Benefit)	$117.0	$58.0	$(12.1)	$—	$162.9
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$218.9	$87.4	$291.9	$(306.8)	$291.4
Capital Expenditures	$307.0	$3.8	$3.2	$—	$314.0
June 30, 2011					
Operating Revenues (b)	$2,294.4	$214.5	$0.4	$(188.9)	$2,320.4
Other Operation and Maintenance	$789.7	$6.6	$2.8	$(186.7)	$612.4
Depreciation and Amortization	$127.3	$36.0	$0.3	$—	$163.6
Operating Income (Loss)	$301.1	$171.9	$(3.0)	$—	$470.0
Equity in Earnings of Unconsolidated Affiliates	$30.7	$—	$(0.2)	$—	$30.5
Interest Expense, Net	$55.3	$32.9	$32.8	$(0.2)	$120.8
Income Tax Expense (Benefit)	$100.4	$55.8	$(18.3)	$—	$137.9
Income from Discontinued Operations, Net of Tax	$—	$—	$11.5	$—	$11.5
Net Income (Loss)	$202.1	$83.3	$280.3	$(285.3)	$280.4
Capital Expenditures	$331.0	$14.9	$1.2	$—	$347.1

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

(b) An elimination for intersegment revenues is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

10 -- 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 approximately one year. We have examined the risks of the entity including the impact of operations and maintenance, dispatch, financing, fuel costs, remaining useful life and other factors, and have determined that we are not the primary beneficiary of this entity. We have concluded that we do not have the power to direct the activities that would most significantly affect the economic performance of the entity over its remaining life.

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the

Form 10-Q

remaining term of approximately 10 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 $283.4 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 six months ended June 30, 2012 and 2011 were $29.6 million and $32.1 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

11 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

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, as discussed below. 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 $21 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 June 30, 2012, we have established reserves of $37.5 million related to future remediation costs.

Historically, 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.

Valley Power Plant Title V Air Permit: The WDNR renewed Valley Power Plant's (VAPP) Title V operating permit in February 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested and were granted an administrative hearing before the WDNR on certain conditions of the permit. We filed a motion for partial summary judgment in that proceeding in March 2012. If the case proceeds to hearing, it would be held in early 2013. In March 2011, the Sierra Club also petitioned the United States Environmental Protection Agency (EPA) for additional reductions and monitoring for particulate matter, and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition. In May 2012, the Sierra Club filed a notice of intent to bring suit to force the EPA to issue a response to that petition.

We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of either proceeding the permit is remanded to the WDNR, the plant will continue to

operate under the previous operating permit.

We also submitted a letter to the EPA in December 2011 with four voluntary goals which include: (1) reducing annual Sulfur Dioxide (SO_2) emissions from the plant to no more than 4,500 tons (a 65% decrease from 2001 emission levels); (2) installing a dry sorbent injection system that is needed to meet the utility Maximum Achievable Control Technology (MACT) rules earlier than the rules require if the installation would provide a direct economic benefit to customers and is approved by the PSCW; (3) holding an open house and tour of VAPP in 2012 to help inform the community on the plant, the unique role that it plays in the community, and to share environmental successes and future plans; and (4) converting VAPP to natural gas fuel by the 2017/2018 timeframe, provided we

Form 10-Q

can demonstrate a direct economic benefit to customers and obtain authorization from the PSCW to do so.

Divested Assets: Pursuant to the sale of the Point Beach Nuclear Power Plant (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 Wisconsin Energy Corporation Retirement Account Plan (Plan) in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged 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 were 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.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. The court approved the settlement on April 3, 2012 and issued its written order on April 20, 2012. Substantially all payments to class members have been made pursuant to the settlement. We do not anticipate further charges as a result of the settlement.

Income Taxes: During the first quarter of 2012, the IRS issued guidance applicable to taxpayers that have taken positions within prior year tax returns relating to the conversion of capitalized assets to repair expense. As a result of this guidance, we have decreased our unrecognized tax benefits by approximately $7.4 million, exclusive of accrued interest.

12 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2012, we paid $118.0 million in interest, net of amounts capitalized, and paid $21.0 million in income taxes, net of refunds. During the six months ended June 30, 2011, we paid $125.1 million in interest, net of amounts capitalized, and received $49.4 million in net refunds from income taxes.

As of June 30, 2012 and 2011, the amount of accounts payable related to capital expenditures was $18.8 million and $51.2 million, respectively.

During the six months ended June 30, 2012 and 2011, total amortization of deferred revenue was $27.5 million and $26.9 million, respectively.

During the six months ended June 30, 2012 and 2011, our equity in earnings from ATC was $31.8 million and $30.7 million, respectively. During the six months ended June 30, 2012 and 2011, distributions received from ATC were $25.8 million and $24.6 million, respectively.

Form 10-Q

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2012

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the second quarter of 2012 with the second quarter of 2011, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Utility Energy Segment	$133.6	$45.5	$88.1
Non-Utility Energy Segment	90.3	2.4	87.9
Corporate and Other	(1.3)	0.3	(1.6)
Total Operating Income	222.6	48.2	174.4
Equity in Earnings of Transmission Affiliate	16.2	1.0	15.2
Other Income, net	8.6	(5.8)	14.4
Interest Expense, net	61.5	(4.1)	57.4
Income from Continuing Operations Before Income Taxes	185.9	39.3	146.6
Income Tax Expense	66.6	(18.0)	48.6
Income from Continuing Operations	$119.3	$21.3	$98.0
Diluted Earnings Per Share from Continuing Operations	$0.51	$0.10	$0.41
Diluted Earnings Per Share from Discontinued Operations	$—	$(0.05)	$0.05

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $133.6 million of operating income during the second quarter of 2012, an increase of $45.5 million, or 51.6%, compared with the second quarter of 2011. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended June 30		
Utility Energy Segment	2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues			
Electric	$772.6	$10.0	$762.6
Gas	151.1	(56.7)	207.8
Other	6.8	(0.7)	7.5
Total Operating Revenues	930.5	(47.4)	977.9
Fuel and Purchased Power	260.0	27.2	287.2
Cost of Gas Sold	75.0	46.8	121.8

Gross Margin	595.5	26.6	568.9
Other Operating Expenses			
Other Operation and Maintenance	358.5	30.3	388.8
Depreciation and Amortization	73.4	(9.5)	63.9
Property and Revenue Taxes	30.0	(1.9)	28.1
Total Operating Expenses	796.9	92.9	889.8
Operating Income	$133.6	$45.5	$88.1

Form 10-Q

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2012 with the second quarter of 2011:

	Three Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$276.9	$17.1	$259.8	1,988.6	153.0	1,835.6
Small Commercial/Industrial	249.7	9.0	240.7	2,169.4	104.2	2,065.2
Large Commercial/Industrial	183.9	(9.5)	193.4	2,409.3	(92.8)	2,502.1
Other - Retail	5.2	—	5.2	36.2	1.3	34.9
Total Retail	715.7	16.6	699.1	6,603.5	165.7	6,437.8
Wholesale - Other	35.6	(4.3)	39.9	368.7	(157.4)	526.1
Resale - Utilities	8.4	(6.8)	15.2	198.7	(238.9)	437.6
Other Operating Revenues	12.9	4.5	8.4	—	—	—
Total	$772.6	$10.0	$762.6	7,170.9	(230.6)	7,401.5
Weather -- Degree Days (a)						
Heating (953 Normal)				765	(272)	1,037
Cooling (159 Normal)				295	182	113

(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 $10.0 million, or 1.3%, when compared to the second quarter of 2011. The most significant factors that caused a change in revenues were:

- Favorable weather as compared to the prior year that increased electric revenues by an estimated $40.1 million.
- Net pricing decreases totaling $12.3 million, which primarily includes a reserve of $10.8 million related to Wisconsin fuel recoveries as a result of lower actual fuel costs than were included in the most recent Wisconsin fuel filing approved by the PSCW.
- An increase in other operating revenues of $7.1 million related to the amortization of the DOE settlement used to offset an increase in fuel costs authorized by the PSCW. For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.
- A $6.8 million reduction in sales for resale due to reduced sales into the MISO Energy Markets.

As measured by cooling degree days, the second quarter of 2012 was 161.1% warmer than the same period in 2011 and 85.5% warmer than normal. The growth in residential and small commercial/industrial sales was primarily driven by the warmer weather. The decrease in large commercial/industrial sales was driven by lower sales to the two iron ore mines in Michigan. If these customers are excluded, sales to our large commercial/industrial customers increased by 0.6%. Wholesale sales decreased primarily due to the low market price of power in 2012 as compared to 2011, which caused some of these customers to obtain energy from the MISO market rather than through our contracts. This reduction did not impact the majority of revenue received from these customers, which is tied to demand.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $27.2 million, or 9.5%, when compared to the second quarter of 2011. This decrease was primarily caused by a 3.1% decrease in total MWh sales and a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

Form 10-Q

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the second quarter of 2012 with the second quarter of 2011. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues decreased by $56.7 million, or 27.3%, and cost of gas sold decreased by $46.8 million, or 38.4%, due to the significantly warmer weather, which resulted in lower therm deliveries, and a decline in the commodity cost of natural gas.

	Three Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gas Operating Revenues	$151.1	$(56.7)	$207.8
Cost of Gas Sold	75.0	46.8	121.8
Gross Margin	$76.1	$(9.9)	$86.0

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2012 with the second quarter of 2011:

	Three Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$48.7	$(5.5)	$54.2	92.5	(24.2)	116.7
Commercial/Industrial	13.4	(3.9)	17.3	50.5	(22.0)	72.5
Interruptible	0.3	(0.2)	0.5	2.6	(0.5)	3.1
Total Retail	62.4	(9.6)	72.0	145.6	(46.7)	192.3
Transported Gas	12.1	(0.1)	12.2	283.1	79.7	203.4
Other	1.6	(0.2)	1.8	—	—	—
Total	$76.1	$(9.9)	$86.0	428.7	33.0	395.7
Weather -- Degree Days (a)						
Heating (953 Normal)				765	(272)	1,037

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

Our gas margin decreased by $9.9 million, or approximately 11.5%, when compared to the second quarter of 2011. This decrease primarily relates to a decrease in sales volumes as a result of warmer weather during the second quarter of 2012 that decreased heating loads. As measured by heating degree days, the second quarter of 2012 was 26.2% warmer than the same period in 2011 and 19.7% warmer than normal. Transported gas volumes for the second quarter of 2012 increased by 39.2% as compared to the same period in 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin. This margin increase was more than offset by a reduction in transportation volumes delivered to higher margin classes that are more weather sensitive than our large transport customers.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $30.3 million, or approximately 7.8%, when compared to the second quarter of 2011. This decrease, which we expect to continue through the remainder of the year, is primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

Form 10-Q

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $9.5 million, or approximately 14.9%, when compared to the second quarter of 2011 primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011, and the emission control equipment for units 5 and 6 of the Oak Creek Air Quality Control System (AQCS) project went into service in March 2012. We expect depreciation expense to continue to increase in 2012 once the emission control equipment for units 7 and 8 of the Oak Creek AQCS project is completed, which we are targeting by the end of summer 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF 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 OC 2).

This segment reflects the lease revenues on the new units as well as the depreciation expense. Operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Three Months Ended June 30, 2012			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$26.9	$82.2	$3.2	$112.3
Operation and Maintenance Expense	0.5	2.2	2.6	5.3
Depreciation Expense	4.8	11.7	0.2	16.7
Operating Income	$21.6	$68.3	$0.4	$90.3

	Three Months Ended June 30, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$26.5	$82.2	$2.6	$111.3
Operation and Maintenance Expense	0.5	3.1	1.5	5.1
Depreciation Expense	5.0	12.9	0.4	18.3
Operating Income	$21.0	$66.2	$0.7	$87.9

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
AFUDC - Equity	$8.0	$(5.5)	$13.5

Other, net	0.6	(0.3	) 0.9
Other Income, net	$8.6	$(5.8	) $14.4

Other income, net decreased by $5.8 million, or approximately 40.3%, when compared to the second quarter of 2011. The decrease in AFUDC - Equity is primarily related to the Glacier Hills Wind Park, which went into service in December 2011, and the emission control equipment for units 5 and 6 of the Oak Creek AQCS project, which went

Form 10-Q

into service in March 2012. We expect AFUDC - Equity to continue to decrease in 2012 once the emission control equipment for units 7 and 8 of the Oak Creek AQCS project is completed, which we are targeting by the end of summer 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gross Interest Costs	$65.1	$(2.0)	$63.1
Less: Capitalized Interest	3.6	(2.1)	5.7
Interest Expense, net	$61.5	$(4.1)	$57.4

Our gross interest costs increased by $2.0 million, or approximately 3.2%, when compared to the second quarter of 2011 primarily because of the issuance of $300 million of long-term debt by Wisconsin Electric in September 2011. Our capitalized interest decreased by $2.1 million primarily because of lower construction work in progress. As a result, our net interest expense increased by $4.1 million, or 7.1%, as compared to the second quarter of 2011.

CONSOLIDATED INCOME TAX EXPENSE

For the second quarter of 2012, our effective tax rate applicable to continuing operations was 35.8% compared to 33.2% for the second quarter of 2011, primarily due to a decrease in the projected 2012 annual tax benefits associated with AFUDC - Equity. For additional information, see Note H -- Income Taxes in our 2011 Annual Report on Form 10-K.

DISCONTINUED OPERATIONS

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

Form 10-Q

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2012

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first six months of 2012 with the first six months of 2011, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Six Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Utility Energy Segment	$342.2	$41.1	$301.1
Non-Utility Energy Segment	178.7	6.8	171.9
Corporate and Other	(2.6)	0.4	(3.0)
Total Operating Income	518.3	48.3	470.0
Equity in Earnings of Transmission Affiliate	31.8	1.1	30.7
Other Income, net	24.6	(2.3)	26.9
Interest Expense, net	120.4	0.4	120.8
Income from Continuing Operations Before Income Taxes	454.3	47.5	406.8
Income Tax Expense	162.9	(25.0)	137.9
Income from Continuing Operations	$291.4	$22.5	$268.9
Diluted Earnings Per Share from Continuing Operations	$1.25	$0.11	$1.14
Diluted Earnings Per Share from Discontinued Operations	$—	$(0.05)	$0.05

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $342.2 million of operating income during the first six months of 2012, an increase of $41.1 million, or 13.6%, compared with the first six months of 2011. The following table summarizes the operating income of this segment between the comparative periods:

	Six Months Ended June 30		
Utility Energy Segment	2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues			
Electric	$1,549.9	$10.7	$1,539.2
Gas	539.6	(192.9)	732.5
Other	19.4	(3.3)	22.7
Total Operating Revenues	2,108.9	(185.5)	2,294.4
Fuel and Purchased Power	515.1	40.9	556.0
Cost of Gas Sold	312.5	151.7	464.2
Gross Margin	1,281.3	7.1	1,274.2
Other Operating Expenses			
Other Operation and Maintenance	734.9	54.8	789.7
Depreciation and Amortization	144.1	(16.8)	127.3

Property and Revenue Taxes	60.1	(4.0	) 56.1
Total Operating Expenses	1,766.7	226.6	1,993.3
Operating Income	$342.2	$41.1	$301.1

Form 10-Q

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first six months of 2012 with the first six months of 2011:

	Six Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$551.5	$8.7	$542.8	3,931.5	65.9	3,865.6
Small Commercial/Industrial	494.9	7.8	487.1	4,321.0	57.1	4,263.9
Large Commercial/Industrial	368.3	(3.7)	372.0	4,853.6	(22.2)	4,875.8
Other - Retail	11.2	(0.1)	11.3	76.6	1.7	74.9
Total Retail	1,425.9	12.7	1,413.2	13,182.7	102.5	13,080.2
Wholesale - Other	72.3	(3.6)	75.9	701.4	(303.5)	1,004.9
Resale - Utilities	25.4	(7.3)	32.7	795.8	(210.4)	1,006.2
Other Operating Revenues	26.3	8.9	17.4	—	—	—
Total	$1,549.9	$10.7	$1,539.2	14,679.9	(411.4)	15,091.3
Weather -- Degree Days (a)						
Heating (4,259 Normal)				3,375	(1,106)	4,481
Cooling (160 Normal)				306	193	113

(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 $10.7 million, or 0.7%, when compared to the first six months of 2011. The most significant factors that caused a change in revenues were:

- Favorable weather as compared to the prior year that increased electric revenues by an estimated $20.7 million.
- An increase in other operating revenues of $13.8 million related to the amortization of the DOE settlement used to offset an increase in fuel costs authorized by the PSCW.
- A decrease in revenues resulting from a reserve of $10.8 million related to Wisconsin fuel recoveries as a result of lower actual fuel costs than were included in the most recent Wisconsin fuel filing approved by the PSCW.
- A $7.3 million reduction in sales for resale due to reduced sales into the MISO Energy Markets.

As measured by cooling degree days, the first six months of 2012 were 170.8% warmer than the same period in 2011 and 91.3% warmer than normal. The growth in residential and small commercial/industrial sales was primarily driven by the warmer weather. The decrease in large commercial/industrial sales was driven by lower sales to the two iron ore mines in Michigan. If these customers are excluded, sales to our large commercial/industrial customers increased by 0.8%. Wholesale sales decreased primarily due to the low market price of power in 2012 as compared to 2011, which caused some of these customers to obtain energy from the MISO market rather than through our contracts. This reduction did not impact the majority of revenue received from these customers, which is tied to demand.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $40.9 million, or 7.4%, when compared to the first six months of 2011. This decrease was primarily caused by a 2.7% decrease in total MWh sales and a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

Form 10-Q

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first six months of 2012 with the first six months of 2011. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues decreased by $192.9 million, or 26.3%, and cost of gas sold decreased by $151.7 million, or 32.7%, due to the significantly warmer weather, which resulted in lower therm deliveries, and a decline in the commodity cost of natural gas.

	Six Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gas Operating Revenues	$539.6	$(192.9)	$732.5
Cost of Gas Sold	312.5	151.7	464.2
Gross Margin	$227.1	$(41.2)	$268.3

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2012 with the first six months of 2011:

	Six Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$146.6	$(26.2)	$172.8	390.7	(117.0)	507.7
Commercial/Industrial	49.2	(13.3)	62.5	221.1	(72.8)	293.9
Interruptible	0.9	(0.2)	1.1	7.6	(1.9)	9.5
Total Retail	196.7	(39.7)	236.4	619.4	(191.7)	811.1
Transported Gas	26.8	(1.0)	27.8	607.2	140.1	467.1
Other	3.6	(0.5)	4.1	—	—	—
Total	$227.1	$(41.2)	$268.3	1,226.6	(51.6)	1,278.2
Weather -- Degree Days (a)						
Heating (4,259 Normal)				3,375	(1,106)	4,481

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

Our gas margin decreased by $41.2 million, or approximately 15.4%, when compared to the first six months of 2011. This decrease primarily relates to a decrease in sales volumes as a result of warmer weather during the first six months of 2012 that decreased heating loads. As measured by heating degree days, the first six months of 2012 were 24.7% warmer than the same period in 2011 and 20.8% warmer than normal. Transported gas volumes for the first six months of 2012 increased by 30.0% as compared to the same period in 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin. This margin increase was more than offset by a reduction in transportation volumes delivered to higher margin classes that are more weather sensitive than our large transport customers.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $54.8 million, or approximately 6.9%, when compared to the first six months of 2011, primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

Form 10-Q

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $16.8 million, or approximately 13.2%, when compared to the first six months of 2011 primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011, and the emission control equipment for units 5 and 6 of the Oak Creek AQCS project went into service in March 2012.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The table below reflects six months of earnings in 2012 and 2011 for PWGS 1, PWGS 2, OC 1 and the common facilities for the Oak Creek expansion. It also reflects six months of earnings in 2012 and approximately five 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.

	Six Months Ended June 30, 2012			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$53.4	$162.5	$3.7	$219.6
Operation and Maintenance Expense	0.6	2.7	4.1	7.4
Depreciation Expense	9.7	23.4	0.4	33.5
Operating Income (Loss)	$43.1	$136.4	$(0.8)	$178.7

	Six Months Ended June 30, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$52.5	$159.4	$2.6	$214.5
Operation and Maintenance Expense	0.6	3.7	2.3	6.6
Depreciation Expense	9.9	25.2	0.9	36.0
Operating Income (Loss)	$42.0	$130.5	$(0.6)	$171.9

CONSOLIDATED OTHER INCOME, NET

	Six Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
AFUDC - Equity	$22.8	$(2.8)	$25.6
Other, net	1.8	0.5	1.3
Other Income, net	$24.6	$(2.3)	$26.9

Other income, net decreased by $2.3 million, or approximately 8.6%, when compared to the first six months of 2011. The decrease in AFUDC - Equity is primarily related to the Glacier Hills Wind Park, which went into service in December 2011, and the emission control equipment for units 5 and 6 of the Oak Creek AQCS project, which went into service in March 2012. We expect AFUDC - Equity to continue to decrease in 2012 once the emission control equipment for units 7 and 8 of the Oak Creek AQCS project is completed, which we are targeting by the end of summer 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

Form 10-Q

CONSOLIDATED INTEREST EXPENSE, NET

	Six Months Ended June 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gross Interest Costs	$130.4	$2.6	$133.0
Less: Capitalized Interest	10.0	(2.2)	12.2
Interest Expense, net	$120.4	$0.4	$120.8

Our gross interest costs decreased by $2.6 million, or approximately 2.0%, when compared to the first six months of 2011 primarily because we retired $450 million of long-term debt in April 2011. This decrease was partially offset by increased interest costs associated with the issuance of $300 million of long-term debt by Wisconsin Electric in September 2011. Our capitalized interest decreased by $2.2 million primarily because of lower construction work in progress. As a result, our net interest expense decreased by $0.4 million, or 0.3%, as compared to the first six months of 2011.

CONSOLIDATED INCOME TAX EXPENSE

For the first six months of 2012, our effective tax rate applicable to continuing operations was 35.9% compared to 33.9% for the first six months of 2011, primarily due to a decrease in the projected 2012 annual tax benefits associated with AFUDC - Equity. For additional information, see Note H -- Income Taxes in our 2011 Annual Report on Form 10-K. We expect our 2012 annual effective tax rate to be between 35.5% and 36.5%.

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 six months ended June 30:

	2012	2011
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$608.7	$648.6
Investing Activities	$(312.6)	$(367.5)
Financing Activities	$(297.1)	$(295.0)

Operating Activities

Cash provided by operating activities declined by $39.9 million during the first six months of 2012 as compared to the same period in 2011. In the first six months of 2011, we expensed approximately $74.0 million of non-cash charges

associated with the amortization of certain regulatory assets and liabilities. The PSCW allowed us to suspend these amortizations in 2012. In addition, in 2011, we received approximately $45.5 million in refunds related to the DOE settlement, which were recorded as a regulatory liability. During the first six months of 2011, we contributed $122.4 million to our qualified benefit plans. We made no such contributions to our qualified plans in the first six months of 2012.

Form 10-Q

Investing Activities

Cash used in investing activities declined by $54.9 million during the first six months of 2012 as compared to the same period in 2011. Our capital expenditures decreased by $33.1 million during the first six months of 2012 as compared to the same period in 2011, primarily because of decreased spending on the Oak Creek AQCS project. During the first six months of 2011, we received proceeds from asset sales totaling $38.5 million, which primarily relates to the sale of our interest in Edgewater Generating Unit 5, as compared to proceeds of $2.8 million during the first six months of 2012. Finally, changes in restricted cash improved our cash from investing activities by $64.8 million. In 2011, we received $45.5 million in proceeds from the settlement with the DOE. The proceeds were treated as restricted cash, which was recorded as cash used in investing activities. In 2012, we released $27.6 million of the proceeds through bill credits and the reimbursement of costs.

Financing Activities

Cash used in financing activities increased by $2.1 million during the first six months of 2012 as compared to the same period in 2011. During the first six months of 2011, we issued $420.0 million of long-term debt in connection with the commercial operation of OC 2 and retired $450 million of long-term debt that matured. We did not issue any long-term debt during the first six months of 2012. In addition, in January 2012, our Board of Directors approved a 15.4% increase in the quarterly common stock dividend effective with the first quarter 2012 dividend payment.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of June 30, 2012, our current liabilities exceeded our current assets by approximately $191.5 million. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place, as well as access to the capital markets to finance our construction program and to refinance current maturities of long-term debt if necessary.

Liquidity

We anticipate meeting our capital requirements during the remainder of 2012 and beyond 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 June 30, 2012, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $559.5 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first six months of 2012, our maximum commercial paper outstanding was $669.9 million with a weighted-average interest rate of 0.28%.

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 June 30, 2012:

Form 10-Q

Company	Total Facility (Millions of Dollars)	Letters of Credit	Credit Available	Facility Expiration
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 June 30, 2012, 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 (Millions of Dollars)	Adjusted
Common Equity	$4,081.1	$4,331.1
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,632.3	4,382.3
Short-Term Debt	559.5	559.5
Total Capitalization	$9,303.3	$9,303.3
Total Debt	$5,191.8	$4,941.8
Ratio of Debt to Total Capitalization	55.8 %	53.1 %

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of June 30, 2012 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 June 30, 2012, 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.

In June 2012, S&P affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, Wisconsin Energy Capital Corporation (WECC) and ERGSS, and revised the ratings outlooks from stable to positive.

In June 2012, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, WECC and ERGSS, and the stable ratings outlooks assigned to each company.

Form 10-Q

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 2011 Annual Report on Form 10-K for additional information related to our credit rating risk.

Capital Requirements

Capital Expenditures: Capital requirements during the remainder of 2012 are expected to be principally for capital expenditures in our utility operations relating to our electric and gas distribution systems, our biomass facility and environmental controls at our Oak Creek generating units. We estimate that we will spend approximately $740 million on consolidated capital expenditures during 2012.

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 June 30, 2012, we have acquired approximately 3.2 million shares in the open market at a cost of $100.0 million pursuant to this program.

On January 19, 2012, our Board of Directors approved a new dividend policy. Pursuant to this new policy, we will target a dividend payout ratio that trends toward 60% of earnings in the year 2014. At the same time, in accordance with that policy, our Board of Directors increased our quarterly dividend to $0.30 per share effective with the first quarter 2012 dividend payment, which would result in annual dividends of $1.20 per share.

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 -- 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 $21.6 billion as of June 30, 2012 compared with $22.2 billion as of December 31, 2011. Our total contractual obligations and other commercial commitments as of June 30, 2012 decreased compared with December 31, 2011 primarily due to periodic payments related to these obligations which were greater than new commitments made in the ordinary course of business.

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 2011 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

All of the PTF units are 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, OC 1 and

Form 10-Q

OC 2 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. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2011 Annual Report on Form 10-K for additional information on PTF.

UTILITY RATES AND REGULATORY MATTERS

2013 Wisconsin Rate Case: On March 23, 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric has asked the PSCW to approve a net bill increase related to non-fuel costs for its Wisconsin retail electric customers of approximately $99.3 million (3.6%) for 2013. This proposed increase reflects an offset to the revenue requirement of approximately $73.3 million related to the proceeds of a renewable energy cash grant we expect to receive under the National Defense Authorization Act (NDAA) upon completion of our biomass facility currently under construction. Wisconsin Electric's proposed plan, if approved by the PSCW, would return the proceeds from the cash grant to customers in the form of bill credits.

Absent the bill credits, the total electric rate increase requested by Wisconsin Electric is approximately $172.6 million (6.2%) for 2013. Wisconsin Electric is requesting an additional increase in electric rates of approximately $37.4 million in 2014, which would result in a 3.6% net bill increase for its Wisconsin retail electric customers. Wisconsin Electric also filed its fuel cost plan for 2013 with the PSCW as required by the Wisconsin fuel rules.

For its natural gas customers, Wisconsin Electric requested a rate decrease of approximately $1.2 million (0.2%) for 2013 with no rate adjustment for 2014. In addition, Wisconsin Electric requested rate increases of approximately $1.3 million (6.0%) for its Valley steam utility customers in 2013 and 2014, and approximately $1.0 million (7.0%) and $1.0 million (6.0%) for its Milwaukee County steam utility customers in 2013 and 2014, respectively.

Wisconsin Gas has asked the PSCW to approve a rate decrease for its natural gas customers of approximately $15.9 million (2.3%) for 2013, with no rate adjustment for 2014.

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 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 (see 2013 Wisconsin Rate Case above).
- Schedules a proceeding to establish a 2012 fuel cost plan.

We received a final written order from the PSCW on November 3, 2011. 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. Pursuant to Michigan law, we self-implemented a $5.7 million interim electric base rate increase in January 2012. This increase was offset by a refund of $2.7 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE, resulting in a net $3.0 million rate increase. In addition, approximately $2.0 million of renewable costs were included in our Michigan fuel recovery rate effective January 1, 2012. The MPSC approved a total increase in electric base rates of $9.2 million annually, effective June 27, 2012, and authorized a 10.1% return on equity.

Form 10-Q

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 were projected higher coal, coal transportation and purchased power costs. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. On January 5, 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE regarding the storage of spent nuclear fuel, resulting in no change in customer bills.

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. In September 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 was 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.

Renewable Energy Portfolio: We are constructing 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. Construction commenced on June 27, 2011. We currently expect to invest between $245 million and $255 million, excluding AFUDC, in the plant and we are targeting completion of the facility by the end of 2013.

Pursuant to the NDAA, which was passed in December 2011, utilities are now able to elect to receive a cash grant for renewable energy projects without the effect of normalization for income tax purposes. As a result of the NDAA, we currently anticipate pursuing a cash grant relating to the biomass facility.

Oak Creek Air Quality Control System: In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008. In March 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. We are targeting completion of the equipment for units 7 and 8 by the end of summer 2012. We currently expect the cost of completing this project to be approximately $750 million ($900 million including AFUDC).

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2011 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

ELECTRIC TRANSMISSION AND ENERGY MARKETS

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, 2012 through May 31, 2013. The resulting ARR valuation and the secured FTRs should mitigate our transmission congestion risk for that period.

Form 10-Q

ENVIRONMENTAL MATTERS

Air Quality

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final utility MACT rule (referred to as the Mercury and Air Toxics Standards rule), which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. While we are continuing to evaluate the impact of the rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with the rule, we currently estimate our capital cost to comply with this rule will be approximately $16 million to $25 million. Based upon our review, the VAPP and Presque Isle Power Plant may require modifications. 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 our other plants well to meet the rule's requirements.

Cross-State Air Pollution Rule: In August 2011, the EPA issued a final rule, the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of Nitrogen Oxide and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation scheme. In February 2012, the EPA issued final technical revisions to the rule and issued a draft final rule which together delay the implementation date for certain penalty provisions that could potentially impact the Presque Isle Power Plant and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with these proposed revisions, however, the Presque Isle Power Plant may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and on December 30, 2011, the U.S. Court of Appeals for the District of Columbia granted a motion to stay the CSAPR pending judicial review of the rule. While the CSAPR is stayed, the CAIR will remain in effect. We are unable to predict the outcome of this review at this time.

Climate Change: Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The regulation of greenhouse gas emissions through legislation and regulation has been, and continues to be, a focus of the President and his administration. Although legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards failed to pass in the U.S. Congress, we expect such legislation to be considered in the future. Any mandatory restrictions on our Carbon Dioxide emissions that may be adopted by Congress or Wisconsin's or Michigan's legislature could result in significant compliance costs that could affect future results of operations, cash flows and financial condition.

In March 2012, the EPA, using its existing authority under the Clean Air Act (CAA), proposed new source performance standards pertaining to greenhouse gas emissions from certain new power plants, including coal-fueled plants, based on the performance of combined cycle natural gas-fueled generating plants. We believe this rule effectively prohibits new conventional coal-fueled power plants. On June 26, 2012, the United States Court of Appeals for the Federal Circuit upheld the EPA's authority to regulate greenhouse gas emissions.

We expect the EPA to attempt to address performance standards for reconstructed and modified generating units in a future rule. Any such rule may impact our ability to do maintenance or modify our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition. For additional information, see the caption "We may face significant costs to comply with the

regulation of greenhouse gas emissions." under Item 1A Risk Factors in our 2011 Annual Report on Form 10-K.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2011 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

Form 10-Q

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. The complaint alleged 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 were 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.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. The court approved the settlement on April 3, 2012 and issued its written order on April 20, 2012. Substantially all payments to class members have been made pursuant to the settlement. We do not anticipate further charges as a result of the settlement.

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. We negotiated a settlement with the DOE for $45.5 million, which we received in the first quarter of 2011. This amount, net of costs incurred, is being returned to customers as part of the PSCW's approval of our 2012 fuel recovery request and the MPSC's rate order in our 2012 Michigan rate case.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States rather than sub-bituminous coal. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We have applied for a new air permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. Upon receiving an air permit, we intend to begin testing sub-bituminous coal in various combinations with bituminous coal to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make the fuel flexibility modifications permanent.

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, 2011. 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 2011 Annual Report on Form 10-K, as well as Note 6 -- Fair Value Measurements and Note 7 --

Derivative Instruments in the Notes to Consolidated Condensed Financial Statements in this report.

Form 10-Q

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures: Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2011 Annual Report on Form 10-K.

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

ENVIRONMENTAL MATTERS

Bluff Collapse: On October 31, 2011, a portion of the bluff at our Oak Creek Power Plant collapsed. The affected area, located south of the AQCS that is currently under construction, was a former ravine that had been filled with coal ash prior to the advent of landfill regulations.

A mixture of soil, coal ash and water, along with several trailers, vehicles and other construction materials from the AQCS construction site, slid down the bluff to the shoreline area. Some of these materials fell into Lake Michigan.

We worked with the U.S. Coast Guard, WDNR and EPA to coordinate an incident action plan for completing the recovery and clean-up efforts. Ash and soil materials were removed from the area, and construction equipment and related materials were removed from Lake Michigan. The clean-up work was completed, and the bluff was stabilized for the winter. We expect permanent bluff reconstruction and stabilization work to be completed during this year's construction season.

We consulted with nearby water utilities and they indicated that there were no impacts to public drinking water supplies. In November 2011, the WDNR conducted a survey of Lake Michigan's lakebed. The survey did not locate

any fly ash or construction materials on the lakebed immediately east and south of the Oak Creek site. Both water quality and sediment sampling have not indicated a serious risk of harm to human health or the environment.

The WDNR issued a Notice of Violation (NOV) along with its investigative findings on March 1, 2012, and an enforcement conference was held with representatives of Wisconsin Electric on March 7, 2012. The NOV involved the north surface water detention basin and a related permit condition. A June 20, 2012 letter from the WDNR rescinded the March 1, 2012 NOV, but alleged non-compliance with certain environmental regulations. We responded to the letter as requested. In late July, the WDNR referred the matter to the Wisconsin Department of Justice (DOJ) for alleged violations of storm water and solid waste statutes and rules. We anticipate the DOJ will

Form 10-Q

seek fines or penalties from us as a result of this incident.

In addition, on November 8, 2011, the Sierra Club provided a Notice of Intent to file a citizens suit under the CAA and Resource Conservation and Recovery Act for alleged violations related to this incident. We have responded that we do not believe there is any basis for a citizen suit. To date, Sierra Club has not indicated whether they intend to file suit.

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.

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, 2011. See Item 1A. Risk Factors in our 2011 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 June 30, 2012:

ISSUER PURCHASES OF EQUITY SECURITIES

2012	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (b)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
April 1 - April 30	4,254	$35.19	—	$200.0
May 1 - May 31	—	$—	—	$200.0
June 1 - June 30	—	$—	—	$200.0
Total	4,254	$35.19	—	

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

(b) 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.

Form 10-Q

ITEM 6. EXHIBITS

Exhibit No.	
3	Articles of Incorporation and Bylaws
3.1	Restated Articles of Incorporation of Wisconsin Energy Corporation, as Amended effective May 21, 2012.
3.2	Bylaws of Wisconsin Energy Corporation, as Amended to May 21, 2012.
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

Form 10-Q

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: August 2, 2012

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