WISCONSIN ENERGY CORP
Form 10-Q
October 30, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-Q

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

For the Quarterly Period Ended

September 30, 2008

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

Large accelerated filer [X] Accelerated filer [ ]

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (September 30, 2008):

Common Stock, $.01 Par Value, 116,918,996 shares outstanding.

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2008

TABLE OF CONTENTS

Part II -- Other Information

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Wisconsin Energy Subsidiaries and Affiliates

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

Other Affiliates	
Minergy	Minergy LLC
Wispark	Wispark LLC
Federal and State Regulatory Agencies	
DOE	United States Department of Energy
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System
Other Terms and Abbreviations	
ALJ	Wisconsin Administrative Law Judge
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors

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:

CPCN	Certificate of Public Convenience and Necessity
Energy Policy Act	Energy Policy Act of 2005
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO bid-based energy markets
Moody's	Moody's Investor Services
OTC	Over-the-Counter
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
PSEG	Public Service Enterprise Group
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Services

Measurements

MW	Megawatt(s) (One MW equals one million watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits
SFAS	Statement of Financial Accounting Standards

Accounting Pronouncements

FIN 46	Consolidation of Variable Interest Entities
FSP SFAS 157-3	Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 123R	Share-Based Payment (Revised 2004)

SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 149	Amendment of SFAS 133 on Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 159	The Fair Value Option for Financial Assets and Financial Liabilities
SFAS 161	Disclosures about Derivative Instruments and Hedging Activities

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

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

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery for new investments as part of our PTF strategy, environmental compliance, transmission service, fuel costs and costs associated with the implementation of the MISO Energy Markets.

- Regulatory factors such as changes in rate-setting policies or procedures; changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; and the siting approval process for new generation and transmission facilities and new pipeline construction.

- Factors affecting the economic climate in our service territories such as customer growth; customer business conditions, including demand for their products and services; and changes in market demand and demographic patterns.

- Factors which impede or delay execution of our PTF strategy, including receipt of necessary state and federal regulatory approvals and permits; timely and successful resolution of legal challenges; opposition to siting of new generating facilities; the adverse interpretation or enforcement of permit conditions by the permitting agencies; construction delays; and obtaining the investment capital from outside sources necessary to implement the strategy.

- Factors which may affect successful implementation of the settlement agreement with the two parties who were challenging the WPDES permit for the Oak Creek expansion.

- The impact of recent and future federal, state and local legislative and regulatory changes, including electric and gas industry restructuring initiatives; implementation of the Energy Policy Act; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; and changes in the application of existing laws and regulations.

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

- The cost and other effects of legal and administrative proceedings, settlements, investigations, claims and changes in those matters.

- Impacts of the significant contraction in the global credit markets affecting the availability and cost of capital, including higher interest rates and shortened maturities for our commercial paper.

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

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

- The effect of accounting pronouncements issued periodically by standard setting bodies.

- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters.

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

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

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

- Other business or investment considerations that may be disclosed from time to time in our SEC filings or in other publicly disseminated written documents, including the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

INTRODUCTION

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

Utility Energy Segment:

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

Non-Utility Energy Segment:

Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2007 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 2007 Annual Report on

Form 10-K, including the financial statements and notes therein.

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	2008	2007
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$852.5	$881.5	$3,230.4	$3,089.1
Operating Expenses				
Fuel and purchased power	344.1	254.3	980.4	716.1
Cost of gas sold	95.9	78.0	841.8	710.4
Other operation and maintenance	320.1	284.3	1,023.2	891.5
Depreciation, decommissioning and amortization	84.1	85.6	242.3	250.9
Property and revenue taxes	26.7	26.2	81.0	77.5
Total Operating Expenses	870.9	728.4	3,168.7	2,646.4
Amortization of Gain	157.4	-	403.4	-
Operating Income	139.0	153.1	465.1	442.7
Equity in Earnings of Transmission Affiliate	14.4	10.9	38.0	32.1
Other Income, net	7.1	14.8	25.6	47.8
Interest Expense, net	38.8	42.5	113.4	127.2
Income from Continuing Operations Before Income Taxes	121.7	136.3	415.3	395.4
Income Taxes	44.7	53.2	156.8	153.5
Income from Continuing Operations	77.0	83.1	258.5	241.9
Income (Loss) from Discontinued				

Operations, Net of Tax	0.5	(0.2)	0.2	(0.6)
Net Income	$77.5	$82.9	$258.7	$241.3
Earnings Per Share (Basic)				
Continuing operations	$0.66	$0.71	$2.21	$2.07
Discontinued operations	-	-	-	(0.01)
Total Earnings Per Share (Basic)	$0.66	$0.71	$2.21	$2.06
Earnings Per Share (Diluted)				
Continuing operations	$0.65	$0.70	$2.19	$2.04
Discontinued operations	-	-	-	-
Total Earnings Per Share (Diluted)	$0.65	$0.70	$2.19	$2.04
Weighted Average Common Shares Outstanding (Millions)				
Basic	116.9	116.9	116.9	116.9
Diluted	118.2	118.2	118.2	118.5
Dividends Per Share of Common Stock	$0.27	$0.25	$0.81	$0.75

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited) September 30, 2008	December 31, 2007
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$ 9,811.1	$ 8,959.1
Accumulated depreciation	(3,277.0)	(3,123.9)

	6,534.1	5,835.2
Construction work in progress	1,722.0	1,764.1
Leased facilities, net	77.6	81.9
Net Property, Plant and Equipment	8,333.7	7,681.2
Investments		
Restricted cash	215.4	323.5
Equity investment in transmission affiliate	266.1	238.5
Other	36.9	42.7
Total Investments	518.4	604.7
Current Assets		
Cash and cash equivalents	23.3	27.4
Restricted cash	235.5	408.1
Accounts receivable	334.3	361.8
Accrued revenues	154.9	312.2
Materials, supplies and inventories	359.5	361.3
Regulatory assets	82.5	164.7
Prepayments and Other	195.8	214.2
Total Current Assets	1,385.8	1,849.7
Deferred Charges and Other Assets		
Regulatory assets	919.9	961.6
Goodwill, net	441.9	441.9
Other	204.0	181.2
Total Deferred Charges and Other Assets	1,565.8	1,584.7
Total Assets	$ 11,803.7	$ 11,720.3
<u>Capitalization and Liabilities</u>		
Capitalization		
Common equity	$ 3,265.3	$ 3,099.2
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,271.1	3,172.5
Total Capitalization	6,566.8	6,302.1
Current Liabilities		
Long-term debt due currently	381.3	352.8
Short-term debt	914.2	900.7
Accounts payable	330.9	478.3
Regulatory liabilities	338.2	563.1
Other	295.0	207.9

Total Current Liabilities	2,259.6	2,502.8
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,157.2	1,314.3
Deferred income taxes - long-term	684.5	551.7
Deferred revenue, net	495.0	347.7
Pension and other benefit obligations	275.1	310.1
Other	365.5	391.6
Total Deferred Credits and Other Liabilities	2,977.3	2,915.4
Total Capitalization and Liabilities	$ 11,803.7	$ 11,720.3

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS

(Unaudited)

		Nine Months Ended September 30	
		2008	2007
		(Millions of Dollars)	
Operating Activities			
Net income		$ 258.7	$ 241.3
Reconciliation to cash			
Depreciation, decommissioning and amortization		250.1	258.2
Amortization of gain		(403.4)	-
Equity in earnings of transmission affiliate		(38.0)	(32.1)
Distributions from transmission affiliate		27.8	24.7
Deferred income taxes and investment tax credits, net		155.4	(22.9)
Deferred revenue		151.1	117.4
Pension plan contribution		(48.4)	-
Change in -	Accounts receivable and accrued revenues	184.8	169.1
	Inventories	1.8	(17.7)

Other current assets	1.4	36.4
Accounts payable	(70.7)	(31.4)
Accrued income taxes, net	(7.0)	16.3
Deferred costs, net	69.9	(60.5)
Other current liabilities	86.8	22.4
Other, net	23.2	(88.5)
Cash Provided by Operating Activities	643.5	632.7
Investing Activities		
Capital expenditures	(889.4)	(842.2)
Proceeds from asset sales, net	13.8	957.6
Proceeds from liquidation of nuclear decommissioning trust	-	552.4
Change in restricted cash	280.7	(969.1)
Proceeds from investments within nuclear decommissioning trust	-	1,528.7
Other activity within nuclear decommissioning trust	-	(1,528.7)
Other	(87.3)	(85.1)
Cash Used in Investing Activities	(682.2)	(386.4)
Financing Activities		
Exercise of stock options	10.0	30.6
Purchase of common stock	(19.9)	(55.7)
Dividends paid on common stock	(94.7)	(87.7)
Issuance of long-term debt	303.0	523.4
Retirement and repurchase of long-term debt	(176.2)	(112.8)
Change in short-term debt	13.5	(80.6)
Other, net	(1.1)	(0.5)
Cash Provided by Financing Activities	34.6	216.7
Change in Cash and Cash Equivalents	(4.1)	463.0
Cash and Cash Equivalents at Beginning of Period	27.4	37.0
Cash and Cash Equivalents at End of Period	$ 23.3	$ 500.0

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

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

(Unaudited)

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8 - Financial Statements and Supplementary Data in our 2007 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary to a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and nine months ended September 30, 2008 are not necessarily indicative of the results which may be expected for the entire fiscal year 2008 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements:

In September 2006, the FASB issued SFAS 157. SFAS 157 defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We partially adopted the provisions of SFAS 157 effective January 1, 2008. In accordance with FSP SFAS 157-b, we have not applied the provisions of SFAS 157 to pension assets, goodwill or asset retirement obligations. The partial adoption of SFAS 157 did not have a significant financial impact on our consolidated financial statements. See Note 6 -- Fair Value Measurements for further information on SFAS 157.

Fair Value Option:

In February 2007, the FASB issued SFAS 159. SFAS 159 permits an entity to measure certain financial assets and financial liabilities at fair value and also establishes presentation and disclosure requirements. SFAS 159 is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We adopted the provisions of SFAS 159 effective January 1, 2008. We did not elect to record any financial assets or liabilities at fair value under SFAS 159.

Disclosures about Derivative Instruments and Hedging Activities:

In March 2008, the FASB issued SFAS 161. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 is effective for fiscal years beginning after November 15, 2008. We are currently evaluating the provisions of SFAS 161, and we expect to adopt it on January 1, 2009.

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

Background:

As part of our PTF strategy, our non-utility subsidiary, We Power, is building four new generating units (PWGS 1 and 2 and OC 1 and 2) that will be leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW, our primary regulator. The leases are designed to recover the capital costs of the plant including a return. PWGS 1 was placed in service in July 2005 and PWGS 2 was placed in service in May 2008. In November 2007, the coal handling system for Oak Creek was placed in service. Under the lease agreements, Wisconsin Electric is responsible for all of the operating costs, including fuel, of our PTF units once they are placed in service. We anticipate that we will recover the operating costs of these plants in rates. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

During Construction:

Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for the PTF units. Our pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as deferred revenue, and will be amortized to revenue over the term of the lease once the respective unit is placed in service. During the construction of our PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest of approximately 6%. Capitalized interest is included in the total cost of the PTF units.

Cash Flows:

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

	Capital Expenditures (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2008	$ -	$48.3	$226.3	$177.0	$451.6	$889.4
2007	$ -	$72.3	$334.6	$114.1	$521.0	$842.2

	Capitalized Interest (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2008	$ -	$7.1	$36.2	$17.8	$61.1	$63.5
2007	$ -	$11.0	$30.1	$9.6	$50.7	$52.0

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

2007	$ -	$24.8	$69.9	$22.7	$117.4	$117.4

Balance Sheet:

As noted above, we collect in current rates carrying costs that are calculated based on the cash expenditures included in CWIP multiplied by our pre-tax cost of capital. The carrying costs are recorded as deferred revenue and included in long-term liabilities. Our total CWIP balance includes cash expenditures, capitalized interest and accruals. The following table identifies key amounts related to our PTF units that are recorded on our balance sheet as of September 30, 2008 and December 31, 2007:

	CWIP - Cash Expenditures (Millions of Dollars)				Total
	PWGS 1	PWGS 2	OC 1	OC 2	PTF
September 30, 2008	$ -	$2.5	$945.1	$487.0	$1,434.6
December 31, 2007	$ -	$286.4	$738.6	$314.7	$1,339.7

	Total CWIP (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2008	$ -	$2.5	$1,043.1	$529.9	$1,575.5	$1,722.0
December 31, 2007	$ -	$313.3	$800.4	$339.9	$1,453.6	$1,764.1

	Net Plant in Service (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2008	$335.0	$358.5	$179.8	$ -	$873.3	$6,534.1
December 31, 2007	$342.0	$ -	$175.0	$ -	$517.0	$5,835.2

	Deferred Revenue, net (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
September 30, 2008	$63.4	$78.0	$251.6	$102.0	$495.0	$495.0
December 31, 2007	$65.5	$62.2	$162.4	$57.6	$347.7	$347.7

Income Statement:

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

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

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

In November 2007, the coal handling system for Oak Creek was placed into service. As of September 30, 2008, this asset had a cost of approximately $183.8 million, which included approximately $9.6 million of capitalized interest. This asset is being depreciated over its estimated useful life of approximately 40 years. The cost of the system, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 32 year period at an annual amount of approximately $24 million.

In May 2008, PWGS 2 was placed in service. As of September 30, 2008, this asset had a cost of approximately $361.4 million, which included approximately $34.0 million of capitalized interest. The asset is being depreciated over its estimated useful life of approximately 37 years. The cost of the plant, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $49 million.

4 -- COMMON EQUITY

Share-Based Compensation Expense:

For a description of share-based compensation, including stock options, restricted stock and performance units, see Note J -- Common Equity in our 2007 Annual Report on Form 10-K. Effective January 1, 2006, we adopted SFAS 123R using the modified prospective method. We utilize the straight-line attribution method for recognizing share-based compensation expense under SFAS 123R. Accordingly, for employee awards classified as equity, share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to outstanding stock options during the period. Shares purchased on the open market by our independent agents are currently used to satisfy the exercise of share-based awards.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	2008	2007
	(Millions of Dollars)			
Stock options	$2.9	$2.4	$8.8	$9.6
Performance units	3.3	1.0	6.2	2.4
Restricted stock	0.2	0.3	0.8	0.8
Share-based compensation expense	$6.4	$3.7	$15.8	$12.8
Related Tax Benefit	$2.5	$1.4	$6.3	$5.1

Stock Option Activity:

During the first nine months of 2008, the Compensation Committee granted 1,362,160 options that had an estimated fair value of $9.93 per share. During the first nine months of 2007, the Compensation Committee granted 1,371,590 options that had an estimated fair value of $8.72 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2008	2007
Risk-free interest rate	2.9% - 3.9%	4.7% - 5.1%
Dividend yield	2.1%	2.2%
Expected volatility	20.0%	13.0% - 20.0%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	6.7	6.0

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

The following is a summary of our stock option activity for the three and nine months ended September 30, 2008:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of July 1, 2008	8,723,117	$36.68		
Granted	-	$ -		
Exercised	(108,572)	$22.56		
Forfeited	-	$ -		
Outstanding as of September 30, 2008	8,614,545	$36.86		
Outstanding as of January 1, 2008	7,694,239	$34.30		
Granted	1,362,160	$48.04		
Exercised	(431,519)	$26.27		
Forfeited	(10,335)	$45.59		
Outstanding as of September 30, 2008	8,614,545	$36.86	6.4	$77.4
Exercisable as of September 30, 2008	5,008,453	$30.76	5.0	$71.5

The intrinsic value of options exercised was $2.5 million and $8.7 million for the three and nine months ended September 30, 2008, and $0.5 million and $24.7 million for the same periods in 2007, respectively. Cash received from options exercised was $10.0 million and $30.6 million for the nine months ended September 30, 2008 and 2007, respectively. The related tax benefit for the same periods was approximately $2.9 million and $9.1 million, respectively.

Stock options to purchase 1,366,625 and 1,357,365 shares of common stock at $47.76 and $48.04 per share, respectively, were outstanding at the end of the third quarter of 2008 but were not included in the computation of diluted earnings per share, because the exercise price of the stock options was greater than the average market price of our common stock during the quarter.

The following table summarizes information about our non-vested options during the three and nine months ended September 30, 2008:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of July 1, 2008	3,614,272	$8.81
Granted	-	$ -
Vested	(8,180)	$8.72
Forfeited	-	$ -
Non-vested as of September 30, 2008	3,606,092	$8.81
Non-vested as of January 1, 2008	3,466,243	$8.21
Granted	1,362,160	$9.93
Vested	(1,211,976)	$8.35
Forfeited	(10,335)	$8.96
Non-vested as of September 30, 2008	3,606,092	$8.81

As of September 30, 2008, total compensation costs related to non-vested stock options not yet recognized was approximately $12.7 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

The following table summarizes information about stock options outstanding as of September 30, 2008:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$12.79 to $23.05	843,177	$21.88	2.9	843,177	$21.88	2.9
$25.31 to $31.07	1,316,486	$26.96	4.3	1,316,486	$26.96	4.3
$33.44 to $48.04	6,454,882	$40.83	7.3	2,848,790	$35.14	6.0
	8,614,545	$36.86	6.4	5,008,453	$30.76	5.0

Restricted Shares:

The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during the three and nine months ended September 30, 2008:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of July 1, 2008	121,523	
Granted	-	
Released / Forfeited	(2,736)	$30.59
Outstanding as of September 30, 2008	118,787	
Outstanding as of January 1, 2008	146,306	
Granted	14,058	$47.61
Released / Forfeited	(41,577)	$30.95
Outstanding as of September 30, 2008	118,787	

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 $0.2 million and $2.0 million for the three and nine months ended September 30, 2008, and $0.2 million and $2.7 million for the same periods in 2007. The related tax benefit was $0.1 million and $0.5 million for the three and nine months ended September 30, 2008, and zero and $0.9 million for the same periods in 2007.

As of September 30, 2008, total compensation cost related to restricted stock not yet recognized was approximately $1.8 million, which is expected to be recognized over the next 38 months on a weighted-average basis.

Performance Units:

In January 2008 and 2007, the Compensation Committee granted 133,855 and 136,905 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three year period. We are accruing compensation costs over the three year period based on our estimate of the final expected value of the award. Performance units earned as of December 31, 2007, were distributed during 2008 and had a total intrinsic value of $5.3 million. The tax benefit realized due to the distribution of performance units was approximately $1.8 million. As of September 30, 2008, total compensation cost related to performance units not yet recognized was approximately $7.3 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

Restrictions:

Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our principal utility subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note J --Common Equity in our 2007 Annual Report on Form 10-K for additional information on these and other restrictions.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Comprehensive Income:

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners. We recorded the following total comprehensive income, net of tax, during the nine months ended September 30:

Comprehensive Income	2008	2007
	(Millions of Dollars)	
Net Income	$258.7	$241.3
Other Comprehensive Income		
Hedging	0.3	0.3
Total Other Comprehensive Income	0.3	0.3
Total Comprehensive Income	$259.0	$241.6

5 -- LONG-TERM DEBT

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. The bonds bore interest at an "auction rate". In March 2008, because of substantial disruptions in the auction rate bond market, Wisconsin Electric purchased (in lieu of redemption) these bonds at a purchase price of par plus accrued interest to the date of purchase. In August 2008, Wisconsin Electric converted the interest rate determination method for the bonds to a weekly rate and they were remarketed to third parties. Letters of credit from Wells Fargo Bank, National Association now provide credit and liquidity support for the remarketed bonds. Prior to the remarketing, Wisconsin Electric held the bonds and they remained outstanding; however because they were held by Wisconsin Electric, they were not reflected in our consolidated long-term debt.

In June 2008, Port Washington Generating Station, LLC issued $156.0 million of 6.00% Senior Notes due June 2033 in a private placement. The Senior Notes have a mortgage style repayment feature with monthly payments of approximately $1.0 million, including principal and interest, and have an average life approximating 15.5 years. The Senior Notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric relating to

PWGS 2. Proceeds from the sale of the Senior Notes were used primarily to repay short-term debt incurred during construction of the PWGS and for other working capital purposes. For further information on PWGS 2, see Note 3 -- Accounting and Reporting for Power the Future Generating Units.

6 -- FAIR VALUE MEASUREMENTS

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

As defined in SFAS 157, fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. Accordingly, we also utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The hierarchy established under SFAS 157 gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

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

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

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

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to SFAS 157 and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

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

The following table summarizes our financial assets and liabilities by level within the fair value hierarchy as of September 30, 2008:

Recurring Fair Value Measures

	Level 1	Level 2	Level 3	Total
		(Millions of Dollars)		
Assets:				
Derivatives	$ -	$2.5	$14.7	$17.2
Total	$ -	$2.5	$14.7	$17.2
Liabilities:				
Derivatives	$16.7	$35.2	$ -	$51.9
Total	$16.7	$35.2	$ -	$51.9

Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

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

Three Months Ended September 30, 2008	Fair Value of Derivatives
	(Millions of Dollars)
Balance as of July 1, 2008	$21.5
Realized and unrealized gains (losses)	-
Purchases, issuances and settlements	(6.8)
Transfers in and/or out of Level 3	-

Balance as of September 30, 2008	$14.7
Change in unrealized gains (losses) relating to instruments still held as of September 30, 2008	$ -

Nine Months Ended September 30, 2008	Fair Value of Derivatives
	(Millions of Dollars)
Balance as of January 1, 2008	$13.0
Realized and unrealized gains (losses)	-
Purchases, issuances and settlements	1.7
Transfers in and/or out of Level 3	-
Balance as of September 30, 2008	$14.7
Change in unrealized gains (losses) relating to instruments still held as of September 30, 2008	$ -

Derivative instruments reflected in Level 3 of the hierarchy include FTRs allocated by MISO that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet in accordance with SFAS 71. See Note 7 -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

7 -- DERIVATIVE INSTRUMENTS

We follow SFAS 133, as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of September 30, 2008, we recognized $63.9 million in regulatory assets and $17.2 million in regulatory liabilities related to derivatives.

8 -- BENEFITS

The components of our net periodic pension and OPEB costs for the three and nine months ended September 30, 2008 and 2007 were as follows:

Pension Benefits	OPEB

Benefit Plan Cost Components	2008	2007	2008	2007
		(Millions of Dollars)		
Three Months Ended September 30				
Net Periodic Benefit Cost				
Service cost	$4.4	$7.5	$2.6	$2.9
Interest cost	17.8	17.8	5.0	4.8
Expected return on plan assets	(21.2)	(21.2)	(4.4)	(3.8)
Amortization of:				
Transition obligation	-	-	-	-
Prior service cost (credit)	0.6	1.4	(3.1)	(3.3)
Actuarial loss	4.1	3.9	1.6	1.8
Net Periodic Benefit Cost	$5.7	$9.4	$1.7	$2.4

	Pension Benefits		OPEB	
Benefit Plan Cost Components	2008	2007	2008	2007
		(Millions of Dollars)		
Nine Months Ended September 30				
Net Periodic Benefit Cost				
Service cost	$13.1	$22.6	$7.8	$8.7
Interest cost	53.3	53.6	15.0	14.4
Expected return on plan assets	(63.6)	(63.4)	(13.2)	(11.4)
Amortization of:				
Transition obligation	-	-	0.2	0.2
Prior service cost (credit)	1.9	4.3	(9.4)	(10.0)
Actuarial loss	12.3	12.9	4.5	5.5
Net Periodic Benefit Cost	$17.0	$30.0	$4.9	$7.4

9 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of September 30, 2008, we had the following guarantees:

	Maximum Potential	Outstanding	Liability

	Future Payments		Recorded
	(Millions of Dollars)		
Wisconsin Energy			
Non-Utility Energy	$ -	$ -	$ -
Other	2.5	2.5	-
Wisconsin Electric	2.9	0.1	-
Subsidiary	5.1	5.1	-
Total	$10.5	$7.7	$ -

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to PSEG, provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement for Wisvest-Connecticut with The United

Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

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

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

Subsidiary guarantees support loan obligations and surety bonds between our affiliates and third parties. In the event our affiliates fail to perform, our subsidiary would be responsible for the obligations.

Postemployment benefits:

Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability, excluding severance benefits, for such benefits was $15.9 million as of September 30, 2008 and $13.9 million as of December 31, 2007.

10 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable operating segments for the three and nine month periods ended September 30, 2008 and 2007 is shown in the following table:

	Reportable Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
		(Millions of Dollars)		
Three Months Ended				
September 30, 2008				
Operating Revenues (b)	$847.5	$40.1	($35.1)	$852.5
Operating Income (Loss)	$112.9	$28.9	($2.8)	$139.0
Interest Expense, net	$25.4	$4.2	$9.2	$38.8
Income Tax Expense (Benefit)	$39.9	$10.4	($5.6)	$44.7
Income from Discontinued Operations, Net of Tax	$ -	$ -	$0.5	$0.5
Net Income (Loss)	$68.1	$15.3	($5.9)	$77.5
Capital Expenditures	$135.9	$111.2	$0.1	$247.2
Three Months Ended				
September 30, 2007				
Operating Revenues (b)	$872.0	$21.1	($11.6)	$881.5
Operating Income	$136.9	$13.5	$2.7	$153.1
Interest Expense, net	$29.2	$1.8	$11.5	$42.5
Income Tax Expense (Benefit)	$52.4	$4.7	($3.9)	$53.2
Loss from Discontinued Operations, Net of Tax	$ -	$ -	($0.2)	($0.2)
Net Income (Loss)	$80.6	$7.2	($4.9)	$82.9
Capital Expenditures	$98.9	$170.7	$0.1	$269.7

Wisconsin Energy Corporation	Reportable Operating Segments Energy Utility	Non-Utility	Corporate & Other (a) & Reconciling Items	Total Consolidated
	(Millions of Dollars)			
Nine Months Ended				
September 30, 2008				
Operating Revenues (b)	$3,224.9	$91.8	($86.3)	$3,230.4
Operating Income (Loss)	$410.0	$63.1	($8.0)	$465.1
Interest Expense, net	$78.1	$7.9	$27.4	$113.4
Income Tax Expense (Benefit)	$148.2	$23.4	($14.8)	$156.8
Income from Discontinued Operations, Net of Tax	$ -	$ -	$0.2	$0.2
Net Income (Loss)	$241.9	$34.6	($17.8)	$258.7
Capital Expenditures	$435.9	$453.2	$0.3	$889.4
Total Assets (c)	$10,203.5	$2,455.6	($855.4)	$11,803.7
Nine Months Ended				
September 30, 2007				
Operating Revenues (b)	$3,076.4	$56.7	($44.0)	$3,089.1
Operating Income (Loss)	$409.1	$34.3	($0.7)	$442.7
Interest Expense, net	$86.4	$5.6	$35.2	$127.2
Income Tax Expense (Benefit)	$156.0	$11.2	($13.7)	$153.5
Loss from Discontinued Operations, Net of Tax	$ -	$ -	($0.6)	($0.6)
Net Income (Loss)	$241.9	$17.8	($18.4)	$241.3
Capital Expenditures	$316.2	$524.1	$1.9	$842.2
Total Assets (c)	$10,292.7	$1,807.4	($337.9)	$11,762.2

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

(b) An elimination for intersegment revenues of $35.2 million and $17.2 million for the three months ended September 30, 2008 and 2007, respectively, and $85.5

million and $51.4 million for the nine months ended September 30, 2008 and 2007, respectively, is included in Operating Revenues.

(c) An elimination of $786.0 million and $307.5 million is included in Total Assets at September 30, 2008 and 2007, respectively, for the PWGS 1, PWGS 2 and Oak Creek coal handling leases between We Power and Wisconsin Electric.

11 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters:

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

Divestitures:

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

Oak Creek Construction:

In July 2008, we received a letter from Bechtel, the contractor of the Oak Creek expansion units, stating that it now forecasts the in-service date of Unit 1 to be delayed three months beyond the guaranteed in-service date of September 29, 2009. The letter also stated that the in-service date of Unit 2 is now forecasted to be one month earlier than the guaranteed in-service date of September 29, 2010. The letter stated that the delays in Unit 1 were caused by severe weather, changes in local labor conditions from those anticipated by the contractor and other factors. The letter also stated that the contractor is analyzing the impacts of these events and expects to submit to us claims for schedule extensions and cost relief. The claims are expected to be submitted by the end of 2008. At this time, because of the lack of information available, we are unable to predict the amount of the claims that may be submitted, or the validity of such claims.

On September 29, 2008, we notified Bechtel that we are invoking the formal dispute resolution process provided in the contract in order to resolve certain issues related to the rights of the parties under the contract. The contract provides for an informal resolution process, followed by mediation, and then binding arbitration. We are currently unable to predict the length or the ultimate outcome of this process.

12 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2008, we paid $96.1 million in interest, net of amounts capitalized, and $2.4 million in income taxes, net of refunds. During the nine months ended September 30, 2007, we paid $98.2 million in interest, net of amounts capitalized, and $151.0 million in income taxes, net of refunds.

13 -- LONG-TERM DEBT -- SUBSEQUENT EVENT

In October 2008, Wisconsin Electric issued $300 million principal amount of 6.00% Debentures due April 1, 2014. Proceeds from the sale were used to repay short-term debt.

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED SEPTEMBER 30, 2008

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the third quarter of 2008 with the third quarter of 2007 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended September 30		
	2008	B (W)	2007
	(Millions of Dollars)		
Utility Energy Segment	$112.9	($24.0)	$136.9
Non-Utility Energy Segment	28.9	15.4	13.5
Corporate and Other	(2.8)	(5.5)	2.7

Total Operating Income	139.0	(14.1)	153.1
Equity in Earnings of Transmission Affiliate	14.4	3.5	10.9
Other Income, net	7.1	(7.7)	14.8
Interest Expense, net	38.8	3.7	42.5
Income from Continuing Operations Before Income Taxes	121.7	(14.6)	136.3
Income Taxes	44.7	8.5	53.2
Income from Continuing Operations	77.0	(6.1)	83.1
Income (Loss) from Discontinued Operations, Net of Tax	0.5	0.7	(0.2)
Net Income	$77.5	($5.4)	$82.9
Diluted Earnings Per Share	$0.65	($0.05)	$0.70

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $112.9 million of operating income during the third quarter of 2008, a decrease of $24.0 million, or 17.5%, compared with the third quarter of 2007. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended September 30		
Utility Energy Segment	2008	B (W)	2007
		(Millions of Dollars)	
Operating Revenues			
Electric	$684.9	($47.7)	$732.6
Gas	156.1	22.7	133.4
Other	6.5	0.5	6.0
Total Operating Revenues	847.5	(24.5)	872.0
Fuel and Purchased Power (a)	345.2	(89.8)	255.4
Cost of Gas Sold	95.9	(17.9)	78.0
Gross Margin	406.4	(132.2)	538.6

Other Operating Expenses			
Other Operation and Maintenance (a)	347.1	(53.8)	293.3
Depreciation, Decommissioning and Amortization (a)	77.5	4.9	82.4
Property and Revenue Taxes	26.3	(0.3)	26.0
Total Operating Expenses	892.0	(156.9)	735.1
Amortization of Gain	157.4	157.4	-
Operating Income	$112.9	($24.0)	$136.9

(a) In September 2007, we sold Point Beach and commenced purchasing power from the new owner under a power purchase agreement. As a result of the sale and the power purchase agreement, our 2008 earnings reflect higher fuel and purchased power costs as compared to 2007. In addition, our 2008 operating income reflects lower other operation and maintenance costs and lower depreciation, decommissioning and amortization costs as we no longer own Point Beach.

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

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the third quarter of 2008 with the third quarter of 2007:

	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2008	B (W)	2007	2008	B (W)	2007

	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$264.0	$9.6	$254.4	2,245.3	(118.4)	2,363.7
Small Commercial/Industrial	245.8	15.0	230.8	2,511.0	(35.7)	2,546.7
Large Commercial/Industrial	179.0	1.2	177.8	2,880.4	(105.5)	2,985.9
Other-Retail	5.0	0.4	4.6	38.8	(0.5)	39.3
Total Retail	693.8	26.2	667.6	7,675.5	(260.1)	7,935.6
Wholesale-Other	(34.6)	(59.7)	25.1	540.0	(10.2)	550.2
Resale-Utilities	15.4	(12.9)	28.3	326.7	(64.0)	390.7
Other Operating Revenues	10.3	(1.3)	11.6	-	-	-
Total	$684.9	($47.7)	$732.6	8,542.2	(334.3)	8,876.5
Weather -- Degree Days (a)						
Heating (131 Normal)				71	(37)	108
Cooling (532 Normal)				478	(89)	567

(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 decreased by $47.7 million, or approximately 6.5%, when compared to the third quarter of 2007. The largest factor in this decline was a one-time $62.5 million FERC-approved refund to our wholesale customers associated with their share of the gain on the sale of Point Beach. Consistent with past practices, the refund was recorded as a reduction in wholesale revenues. As the refund came from the restricted cash associated with the sale of Point Beach, a corresponding entry was made to amortize the gain.

In addition, we estimate that third quarter revenues were down by approximately $17.3 million as a result of a cool summer that negatively affected the demand for air conditioning. As measured by cooling degree days, the third quarter of 2008 was 15.7% cooler than the same period in 2007 and 10.2% cooler than normal. Opportunity sales were down by $12.9 million, primarily because of the cooler summer weather. Partially offsetting these decreases, we estimate that our electric revenues were approximately $53.1 million higher than the same period in 2007 as a result of 2008 pricing increases in Wisconsin. For further information on these rate increases, see Factors Affecting Results, Liquidity and Capital Resources - Utility Rates and Regulatory Matters below.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $89.8 million, or 35.2%, when compared to the third quarter of 2007. The largest factor related to this increase was the power purchase agreement we entered into in connection with the sale of Point Beach, which increased costs by approximately $103.2 million. After adjusting for the Point Beach power purchase agreement, fuel and purchased power costs decreased by approximately $13.4 million, or 5.2%. This decrease was primarily due to lower costs resulting from a 3.8% reduction in MWh sales in the third quarter of 2008 as compared with the same period in 2007 due to cooler summer weather in 2008.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the third quarter of 2008 with the third quarter of 2007. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by $22.7 million, or 17.0%, primarily because of higher natural gas prices and pricing increases we received in the January 2008 PSCW rate order.

	Three Months Ended September 30		
	2008	B (W)	2007
	(Millions of Dollars)		
Gas Operating Revenues	$156.1	$22.7	$133.4
Cost of Gas Sold	95.9	(17.9)	78.0
Gross Margin	$60.2	$4.8	$55.4

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the third quarter of 2008 with the third quarter of 2007:

	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2008	B (W)	2007	2008	B (W)	2007
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$35.6	$2.6	$33.0	46.1	(1.3)	47.4
Commercial/Industrial	10.0	0.6	9.4	32.7	(0.5)	33.2
Interruptible	0.5	0.1	0.4	4.1	(0.3)	4.4
Total Retail Gas Sales	46.1	3.3	42.8	82.9	(2.1)	85.0
Transported Gas	10.8	(0.4)	11.2	188.2	(13.1)	201.3
Other	3.3	1.9	1.4	-	-	-
Total	$60.2	$4.8	$55.4	271.1	(15.2)	286.3
Weather -- Degree Days (a)						
Heating (131 Normal)				71	(37)	108

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

Our gas margins increased by $4.8 million, or approximately 8.7%, when compared to the third quarter of 2007. We estimate that our third quarter 2008 revenues were $3.7 million higher than the third quarter of 2007 reflecting pricing increases that we received in the January 2008 PSCW rate order.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by approximately $53.8 million, or 18.3%, when compared to the third quarter of 2007. The January 2008 PSCW rate order discussed above allowed for pricing increases related to transmission costs, PTF lease costs and the amortization of other deferred costs. We estimate these items were approximately $70.3 million higher during the third quarter of 2008 as compared to the same period in 2007. Additionally, approximately $16.4 million of the increase related to the operation and maintenance of our power plants and electric distribution system. These increases were partially offset by an estimated $33.4 million reduction in nuclear operation and maintenance expense related to the sale of Point Beach as we no longer own the plant.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense decreased by $4.9 million, or approximately 5.9%, when compared to the third quarter of 2007. This decrease was primarily due to the sale of Point Beach, which was partially offset by plant additions. In May 2008, the Blue Sky Green Field wind project was placed in service. As of September 30, 2008, the cost of this project was approximately $295.3 million, including AFUDC, and the annual depreciation expense is expected to be approximately $10.8 million.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements with our regulators to allow for the net gain on the sale of approximately $902.2 million to be used for the benefit of our customers. The majority of the benefits are being returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it is being amortized to the income statement as we issue bill credits or make refunds to our customers. When the bill credits and refunds are issued to customers, we transfer cash from the restricted balances to the unrestricted balances, adjusted for taxes. During the third quarter 2008, we issued approximately $94.9 million of bill credits to our retail customers and issued a refund of approximately $62.5 million to wholesale customers in a one-time FERC-approved settlement.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $28.9 million of operating income for the third quarter of 2008 as compared to $13.5 million for the third quarter of 2007. The increase primarily relates to lease income from PWGS 2, which was placed into service in May 2008, and the coal handling system for Oak Creek, which was placed into service during November 2007.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by approximately $7.7 million, or 52.0%, when compared to the third quarter of 2007. In connection with the January 2008 PSCW rate order, we stopped accruing carrying charges on regulatory assets as we are now allowed a current return on them. In 2007, we accrued carrying charges of approximately $7.4 million on regulatory assets.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended September 30	
Interest Expense	2008	2007
	(Millions of Dollars)	
Gross Interest Costs	$59.1	$62.9
Less: Capitalized Interest	20.3	20.4
Interest Expense, net	$38.8	$42.5

Our gross interest costs decreased by $3.8 million, or 6.0%, when compared to the third quarter of 2007, primarily due to lower short-term interest rates. Our capitalized interest decreased by $0.1 million during the third quarter of 2008, primarily because we stopped capitalizing interest on PWGS 2 once it was placed in service. This was partially offset by higher capitalized interest related to the Oak Creek units

under construction. As a result, our net interest expense declined by $3.7 million, or 8.7%, as compared to the third quarter of 2007.

CONSOLIDATED INCOME TAXES

For the third quarter of 2008, our effective tax rate applicable to continuing operations was 36.7% compared to 39.0% for the third quarter of 2007. For additional information, see Note H -- Income Taxes in our 2007 Annual Report on Form 10-K. We expect our 2008 annual effective tax rate to be between 36.0% and 38.0%.

RESULTS OF OPERATIONS -- NINE MONTHS ENDED SEPTEMBER 30, 2008

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first nine months of 2008 with the first nine months of 2007 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Nine Months Ended September 30		
	2008	B (W)	2007
		(Millions of Dollars)	
Utility Energy Segment	$410.0	$0.9	$409.1
Non-Utility Energy Segment	63.1	28.8	34.3
Corporate and Other	(8.0)	(7.3)	(0.7)
Total Operating Income	465.1	22.4	442.7
Equity in Earnings of Transmission Affiliate	38.0	5.9	32.1
Other Income, net	25.6	(22.2)	47.8
Interest Expense, net	113.4	13.8	127.2
Income from Continuing Operations Before Income Taxes	415.3	19.9	395.4
Income Taxes	156.8	(3.3)	153.5
Income from Continuing Operations	258.5	16.6	241.9
Income (Loss) from Discontinued Operations, Net of Tax	0.2	0.8	(0.6)
Net Income	$258.7	$17.4	$241.3
Diluted Earnings Per Share	$2.19	$0.15	$2.04

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $410.0 million of operating income during the first nine months of 2008, an increase of $0.9 million, or 0.2%, compared with the first nine months of 2007. The following table summarizes the operating income of this segment between the comparative periods:

Utility Energy Segment	Nine Months Ended September 30 2008	B (W)	2007
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,022.0	($15.5)	$2,037.5
Gas	1,171.7	159.9	1,011.8
Other	31.2	4.1	27.1
Total Operating Revenues	3,224.9	148.5	3,076.4
Fuel and Purchased Power (a)	983.5	(264.3)	719.2
Cost of Gas Sold	841.8	(131.4)	710.4
Gross Margin	1,399.6	(247.2)	1,646.8
Other Operating Expenses			
Other Operation and Maintenance (a)	1,086.1	(167.1)	919.0
Depreciation, Decommissioning and Amortization (a)	226.3	15.4	241.7
Property and Revenue Taxes	80.6	(3.6)	77.0
Total Operating Expenses	3,218.3	(551.0)	2,667.3
Amortization of Gain	403.4	403.4	-
Operating Income	$410.0	$0.9	$409.1

(a) In September 2007, we sold Point Beach and commenced purchasing power from the new owner under a power purchase agreement. As a result of the sale and the power purchase agreement, our 2008 earnings reflect higher fuel and purchased power costs as compared to 2007. In addition, our 2008 operating income reflects lower other operation and maintenance costs and lower depreciation, decommissioning and amortization costs as we no longer own Point Beach.

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first nine months of 2008 with the first nine months of 2007:

	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2008	B (W)	2007	2008	B (W)	2007
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$732.4	$31.0	$701.4	6,332.1	(141.9)	6,474.0
Small Commercial/Industrial	677.5	25.2	652.3	7,067.3	(73.5)	7,140.8
Large Commercial/Industrial	508.8	(10.5)	519.3	8,424.2	(85.8)	8,510.0
Other Retail	15.5	1.1	14.4	121.9	(0.9)	122.8
Total Retail Sales	1,934.2	46.8	1,887.4	21,945.5	(302.1)	22,247.6
Wholesale - Other	29.4	(43.2)	72.6	1,733.4	143.0	1,590.4
Resale-Utilities	29.5	(16.0)	45.5	640.1	(65.5)	705.6
Other Operating Revenues	28.9	(3.1)	32.0	-	-	-
Total	$2,022.0	($15.5)	$2,037.5	24,319.0	(224.6)	24,543.6
Weather -- Degree Days (a)						
Heating (4,361 Normal)				4,586	327	4,259
Cooling (709 Normal)				587	(168)	755

(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 decreased by $15.5 million, or approximately 0.8%, when compared to the first nine months of 2007. The largest factor in this decline was a one-time

31

$62.5 million FERC-approved refund to our wholesale customers associated with their share of the gain on the sale of Point Beach. Consistent with past practices, the refund was recorded as a reduction in wholesale revenues. As the refund came from the restricted cash associated with the sale of Point Beach, a corresponding entry was made to amortize the gain.

We also estimate that weather reduced our revenues by approximately $27.2 million for the nine months ended September 30, 2008 as compared to the same period in 2007. As measured by cooling degree days, the first nine months of 2008 were 22.3% cooler than the same period in 2007 and 17.2% cooler than normal. Opportunity sales declined by approximately $16.0 million, primarily because of the cooler weather. In addition, we experienced a $9.0 million decrease in revenue related to the settlement of a billing dispute with our largest customers, two iron ore mines, that occurred in 2007. Partially offsetting these decreases, we estimate that our electric revenues were approximately $96.6 million higher than the same period in 2007 because of pricing increases that we received in the January 2008 PSCW rate case, the interim April 2008 and final July 2008 PSCW fuel orders and a wholesale rate increase effective in May 2007. For further information on these rate increases, see Factors Affecting Results, Liquidity and Capital Resources - Utility Rates and Regulatory Matters below.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $264.3 million, or approximately 36.7%, when compared to the first nine months of 2007. The largest factor related to this increase was the power purchase agreement we entered into in connection with the sale of Point Beach, which increased costs by approximately $225.3 million. In addition, in connection with the January 2008 PSCW rate order, we recorded a $41.2 million one-time amortization of deferred fuel costs in the first quarter of 2008. After adjusting for the Point Beach power purchase agreement and one-time amortization of deferred fuel cost, fuel and purchased power costs decreased by approximately $2.2 million, or 0.3%. Cost increases resulting from higher natural gas prices, purchased energy and coal and related transportation prices were more than offset by lower costs resulting from reduced MWh sales and higher coal unit generation during the first nine months of 2008 as compared to the same period in 2007.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first nine months of 2008 with the first nine months of 2007. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by $159.9 million, or 15.8%, primarily because of higher natural gas prices and pricing increases we received in the January 2008 PSCW rate order.

	Nine Months Ended September 30		
	2008	B (W)	2007
	(Millions of Dollars)		
Gas Operating Revenues	$1,171.7	$159.9	$1,011.8
Cost of Gas Sold	841.8	(131.4)	710.4
Gross Margin	$329.9	$28.5	$301.4

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first nine months of 2008 with the first nine months of 2007:

Nine Months Ended September 30

Gas Utility Operations	Gross Margin 2008	Gross Margin B (W)	Gross Margin 2007	Therm Deliveries 2008	Therm Deliveries B (W)	Therm Deliveries 2007
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$206.5	$15.9	$190.6	558.2	24.5	533.7
Commercial/Industrial	74.8	9.8	65.0	339.7	23.0	316.7
Interruptible	1.8	0.3	1.5	17.1	0.3	16.8
Total Retail Gas Sales	283.1	26.0	257.1	915.0	47.8	867.2
Transported Gas	38.4	0.4	38.0	670.2	(13.3)	683.5
Other	8.4	2.1	6.3	-	-	-
Total	$329.9	$28.5	$301.4	1,585.2	34.5	1,550.7
Weather -- Degree Days (a)						
Heating (4,361 Normal)				4,586	327	4,259

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

Our gas margins increased by $28.5 million, or 9.5%, when compared to the first nine months of 2007. We estimate that approximately $15.3 million of this increase related to pricing increases that we received in the January 2008 PSCW rate order. Additionally, we estimate that weather had a positive impact on sales of $6.3 million. As measured by heating degree days, the first nine months of 2008 were 7.7% cooler than the same period in 2007 and 5.2% cooler than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by approximately $167.1 million, or 18.2%, when compared to the first nine months of 2007. The January 2008 PSCW rate order discussed above allowed for pricing increases related to transmission costs, PTF lease costs and the amortization of other deferred costs. We estimate these items were approximately $196.4 million higher during the first nine months of 2008 as compared to the same period in 2007. Additionally, approximately $45.8 million of the increase related to the operation and maintenance of our power plants and electric distribution system. In addition, in connection with the January 2008 PSCW rate order, we recorded a $43.8 million amortization of deferred bad debt costs in the first quarter of 2008. These increases were partially offset by an estimated $119.0

million reduction in nuclear operation and maintenance expense related to the sale of Point Beach as we no longer own the plant.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense decreased by $15.4 million, or approximately 6.4%, when compared to the first nine months of 2007. This decrease was primarily due to the result of the sale of Point Beach, which was partially offset by plant additions. In May 2008, the Blue Sky Green Field wind project was placed in service. As of September 30, 2008, the cost of this project was approximately $295.3 million, including AFUDC, and the annual depreciation expense is expected to be approximately $10.8 million.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements with our regulators to allow for the net gain on the sale of approximately $902.2 million to be used for the benefit of our customers. The majority of the benefits are being returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it is being amortized to the income statement as we issue bill credits or make refunds to our customers. When the bill credits and refunds are issued to customers, we transfer cash from the restricted balances to the unrestricted balances, adjusted

for taxes. During the first nine months of 2008, we issued approximately $255.9 million of bill credits to our retail customers and issued a refund of approximately $62.5 million to wholesale customers in a one-time FERC approved settlement. In addition, pursuant to the January 2008 PSCW rate order, during the first quarter of 2008 we recorded an $85.0 million amortization of a portion of the gain to reflect the recovery of the amortization of $85.0 million of regulatory assets ($41.2 million related to deferred fuel costs and $43.8 million related to deferred bad debt costs).

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $63.1 million of operating income for the first nine months of 2008 as compared to $34.3 million for the first nine months of 2007. The increase primarily relates to lease income from PWGS 2, which was placed into service in May 2008, and the coal handling system for Oak Creek, which was placed into service during November 2007.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by approximately $22.1 million, or 46.2%, when compared to the first nine months of 2007. In connection with the January 2008 PSCW rate order, we stopped accruing carrying charges on those regulatory assets as we are now allowed a current return on them. In 2007, we accrued carrying charges of $20.8 million on regulatory assets.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Nine Months Ended September 30	
	2008	2007
	(Millions of Dollars)	
Gross Interest Costs	$176.9	$179.2
Less: Capitalized Interest	63.5	52.0
Interest Expense, net	$113.4	$127.2

Our gross interest costs decreased by $2.3 million, or 1.3%, during the nine months ended September 30, 2008 when compared with the same period in 2007, primarily because of lower short-term interest rates. Our capitalized interest increased by $11.5 million, primarily because of increased construction in progress at our Oak Creek units. As a result, our net interest expense declined by $13.8 million, or 10.8%, as compared to the first nine months of 2007.

CONSOLIDATED INCOME TAXES

For the first nine months of 2008, our effective tax rate applicable to continuing operations was 37.8% compared to 38.8% for the first nine months of 2007. For additional information, see Note H -- Income Taxes in our 2007 Annual Report on Form 10-K. We expect our 2008 annual effective tax rate to be between 36.0% and 38.0%.

34

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the first nine months of 2008 and 2007:

	Nine Months Ended September 30	
Wisconsin Energy Corporation	2008	2007
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$643.5	$632.7
Investing Activities	($682.2)	($386.4)
Financing Activities	$34.6	$216.7

Operating Activities

Cash provided by operating activities was $643.5 million during the nine months ended September 30, 2008, which was $10.8 million higher than 2007. During the first nine months of 2008, we experienced higher cash earnings and lower tax payments and working capital requirements.

During the first nine months of 2008, our cash taxes were $148.6 million lower than the first nine months of 2007, primarily due to higher deferred taxes as a result of additional tax depreciation expense. In accordance with IRS guidelines, we completed a review in 2008 and concluded that certain timing items that historically had been capitalized and depreciated for tax purposes could be deducted currently. For additional information regarding cash paid for income taxes, see Note 12 -- Supplemental Cash Flow Information.

Investing Activities

Cash used in investing activities was $682.2 million during the nine months ended September 30, 2008, which was $295.8 million higher than the same period in 2007. This increase reflects the sale of Point Beach and the liquidation of nuclear decommissioning trusts in 2007 and increased capital expenditures during 2008, partially offset by the release of restricted cash to us.

During the first nine months of 2008, we released $280.7 million of restricted cash. In September 2007, we sold Point Beach and received approximately $924 million and retained approximately $552 million of decommissioning funds. We placed approximately $924 million in restricted accounts to be used for the payment of taxes and for the benefit of our customers. We release the restricted cash, adjusted for taxes, as we issue bill credits to our customers, which is reflected as an amortization of the gain on our income statement.

During the first nine months of 2008, our capital expenditures increased $47.2 million, primarily due to increased utility construction spending including payments related to our wind generation project. This increase was anticipated.

Financing Activities

Cash provided by financing activities was $34.6 million during the nine months ended September 30, 2008, compared to $216.7 million during the same period in 2007. In June 2008, PWGS issued $156.0 million of debt related to the commercial operation of PWGS 2. In addition, Wisconsin Electric

purchased (in lieu of redemption) $147 million of tax-exempt bonds outstanding, converted the interest rate determination method and remarketed them to third parties. For further information regarding the tax-exempt bonds, see Note 5 -- Long Term Debt. In the first nine months of 2007, we received proceeds of $523.4 million from the issuance of debt, including $500 million aggregate principal amount of Junior Notes offered in May 2007. We used the net proceeds of the Junior Notes to pay down short-term debt incurred to fund our PTF construction and for other working capital purposes.

During the first nine months of 2008, we received proceeds of $10.0 million related to the exercise of stock options, compared to $30.6 million in the first nine months of 2007. Instead of issuing new shares for these stock options, we instructed our plan agent to purchase common stock in the open market at a cost of $19.9 million, compared to $55.7 million in the first nine months of 2007. This cost is included in Purchase of common stock on our Consolidated Condensed Statements of Cash Flows.

CAPITAL RESOURCES AND REQUIREMENTS

Capital Resources

We anticipate meeting our capital requirements during the remaining three months of 2008 primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities depending on market conditions and other factors. Beyond 2008, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings and the issuance of debt securities.

During the third quarter of 2008, the global credit markets suffered a significant contraction, including the failure of some large financial institutions. As a result, interest rates on our short-term and variable rate tax-exempt debt increased and, at times, we were unable to issue commercial paper with maturities longer than one day. However, despite the turmoil in the credit markets, Wisconsin Electric was able to remarket its $147 million tax-exempt bonds in August 2008 and to issue in October 2008 $300 million of 6.00% Debentures due April 1, 2014.

As indicated above, despite the recent turmoil in the global credit markets, we still currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets and internally generated cash. Over the past two months, we have experienced an increase in short-term interest rates in connection with the credit turmoil.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas credit agreements provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, provided approximately $80 million of commitments under our bank back-up credit facilities on a consolidated basis. We have no current plans to replace Lehman's commitments. Excluding Lehman's commitments, as of September 30, 2008 we had approximately $1.6 billion of available, undrawn lines under our bank back-up credit facilities. As of September 30, 2008, we had approximately $914.2 million of short-term debt outstanding on a consolidated basis that was supported by the available lines of credit. The net proceeds from Wisconsin Electric's issuance of $300 million of debentures on October 1, 2008 were used to repay short-term debt.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities as of September 30, 2008:

Company	Total Facility *	Letters of Credit	Credit Available *	Facility Expiration	Facility Term
		(Millions of Dollars)			

Wisconsin Energy	$857.5	$1.5	$856.0	April 2011	5 year
Wisconsin Electric	$476.4	$4.1	$472.3	March 2011	5 year
Wisconsin Gas	$285.8	$ -	$285.8	March 2011	5 year

* Excludes Lehman's commitments

In connection with the conversion of the interest rate determination method for certain Wisconsin Electric tax-exempt bonds in August 2008, Wisconsin Electric terminated its $100 million six-month bank back-up credit facility that was scheduled to expire in September 2008.

The following table shows our actual capitalization structure as of September 30, 2008, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the majority of rating agencies currently view the Junior Notes:

Capitalization Structure	Actual		Adjusted	
	(Millions of Dollars)			
Common Equity	$3,265.3	41.5%	$3,515.3	44.7%
Preferred Stock of Subsidiary	30.4	0.4%	30.4	0.4%
Long-Term Debt (including current maturities)	3,652.4	46.5%	3,402.4	43.3%
Short-Term Debt	914.2	11.6%	914.2	11.6%
Total Capitalization	$7,862.3	100.0%	$7,862.3	100.0%
Total Debt	$4,566.6		$4,316.6	
Ratio of Debt to Total Capitalization		58.1%		54.9%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of September 30, 2008, is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. The bonds bore interest at an "auction rate". In March 2008, because of substantial disruptions in the auction rate bond market, Wisconsin Electric purchased (in lieu of redemption) these bonds at a purchase price of par plus accrued interest to the date of

purchase. In August 2008, Wisconsin Electric converted the interest rate determination method for the bonds to a weekly rate and they were remarketed to third parties. Letters of credit from Wells Fargo Bank, National Association now provide credit and liquidity support for the remarketed bonds. Prior to the remarketing, Wisconsin Electric held the bonds and they remained outstanding; however, because they were held by Wisconsin Electric, they were not reflected in our consolidated long-term debt.

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and the debt securities and preferred stock of our subsidiaries by S&P, Moody's and Fitch as of September 30, 2008:

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

In July 2008, S&P affirmed the corporate credit ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and changed the ratings outlooks assigned each company from stable to positive.

On April 30, 2008, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and the stable ratings outlook of Wisconsin Electric and Wisconsin Gas. Fitch also revised the ratings outlook of Wisconsin Energy and Wisconsin Energy Capital Corporation from negative to stable.

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

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

Capital Requirements

Capital requirements during the remainder of 2008 are expected to be principally for capital expenditures and long-term debt maturities. Our 2008 annual consolidated capital expenditure budget is approximately $1.2 billion.

Pension Plans:

We have noncontributory defined benefit pension plans that cover substantially all of our employees. During 2008, we contributed $48.4 million to our pension plans. Our future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For the nine months ended September 30, 2008, the returns on our pension plan assets were significantly below our expected annual returns of 8.5%. Based on actual plan returns through September 30, 2008, we believe that we may contribute approximately $180 million to our pension plans during 2009.

Off-Balance Sheet Arrangements:

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit, which support construction projects, commodity contracts and other payment obligations. We continue to believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note 9 -- Guarantees in the Notes to Consolidated Condensed Financial Statements in this report.

We have identified two tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of any of these two variable interest entities as defined by FIN 46. As a result, we do not consolidate these entities. Instead, we account for one of these contracts as a capital lease and for the other contract as an operating lease. A similar power purchase agreement expired during the second quarter of 2008. For additional information, see Note G -- Variable Interest Entities in our 2007 Annual Report on Form 10-K. We have included our contractual obligations under these two contracts in our evaluation of Contractual Obligations/Commercial Commitments discussed below.

Contractual Obligations/Commercial Commitments:

Our total contractual obligations and other commercial commitments were approximately $21.1 billion as of September 30, 2008 compared with $21.4 billion as of December 31, 2007. As of September 30, 2008, the largest amounts of total contractual obligations and other commercial commitments relate to purchase obligations of $13.8 billion primarily associated with the procurement of fuel and purchased power and $6.7 billion related to long-term debt obligations. Our total contractual obligations and other commercial commitments as of September 30, 2008 decreased compared with December 31, 2007 primarily due to periodic payments related to these types of obligations which were greater than new commitments made in the ordinary course of business during the nine month period ended September 30, 2008.

FACTORS AFFECTING RESULTS, LIQUDITY 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 2007 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion by We Power. We Power will lease the new units to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the lease payments in its electric rates. Both PWGS units have been completed and are in service. The Oak Creek units are still under construction. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2007 Annual Report on Form 10-K and Note 3 -- Accounting and Reporting for Power the Future Generating Units in the Notes to Consolidated Condensed Financial Statements in this report for additional information on PTF.

Oak Creek Expansion:

Construction Status

In June 2005, construction commenced on two 615 MW coal-fired units (the Oak Creek expansion) at a site adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. Bechtel is the contractor of the units under a fixed price contract, subject to certain defined price adjustments. The total cost of the two units was estimated to be $2.191 billion.

In July 2008, Bechtel notified us in a letter that it now forecasts the in-service date of Unit 1 to be delayed three months beyond the guaranteed contract date of September 29, 2009. Bechtel also advised us in the letter that it now forecasts the in-service date of Unit 2 to be one month earlier than the guaranteed contract date of September 29, 2010.

According to the letter, reasons for the delay of Unit 1 include severe winter weather experienced during the winters of 2006-2007 and 2007-2008, exacerbated by severe rain storms in April and June of 2008, changes in local labor conditions from those anticipated by Bechtel, the cumulative impact of a large number of change orders and delay in receiving full notice to proceed in 2005 as a result of the court challenges by certain opposition groups to the CPCN for the Oak Creek expansion.

The letter states that Bechtel is still analyzing the impact of these events, and that it expects to submit to us claims for schedule extensions and cost relief with required justification by the end of 2008. We will review these claims when they arrive to determine if we believe Bechtel is entitled to any schedule and/or cost relief.

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

We estimate that for each month of delay of the in-service date of Unit 1, earnings for 2009 would be reduced by $0.03 per share after-tax compared to what they otherwise would have been. In addition, we estimate that for each month of acceleration of the in-service date of Unit 2, earnings for 2010 would increase by $0.02 per share after-tax compared to what they otherwise would have been.

On September 29, 2008, we notified Bechtel that we are invoking the formal dispute resolution process provided in the contract in order to resolve certain issues related to the rights of the parties under the contract. The contract provides for an informal resolution process, followed by mediation, and then binding arbitration. We are currently unable to predict the length or the ultimate outcome of this process.

WPDES Permit

A contested case hearing for the WPDES permit was held in March 2006. The ALJ upheld the issuance of the permit in a decision issued in July 2006. In August 2006, the opponents filed in Dane County Circuit Court for judicial review of the ALJ's decision upholding the issuance of the permit. In March 2007, the Dane County Circuit Court affirmed in part the decision by the ALJ to uphold the WDNR's issuance of the permit. The Court also remanded certain aspects of the ALJ's decision for further consideration based on the January 2007 decision by the United States Court of Appeals for the Second Circuit concerning the federal rule on cooling water intake systems for existing facilities (the Phase II rule) (Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) (2d Cir. 2007)). The Second Circuit found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential rulemaking. In July 2007 the EPA formally suspended the Phase II rule in its entirety and directed states to use their "best professional judgment" in evaluating intake systems for existing facilities.

In November 2007, the ALJ determined that the expansion units are new facilities under Section 316(b) of the Clean Water Act. The ALJ did not vacate the WPDES permit or any other permit necessary to continue construction of the two units, pointing out that, based upon the present record, the water intake system currently under construction as part of the Oak Creek expansion may be permittable under the standards that apply to new facilities.

The ALJ remanded the WPDES permit to the WDNR and directed the WDNR to reissue or modify the permit to reflect "best technology available" to comply with the standards applicable to new facilities under Wisconsin state law. As part of the decision, the ALJ restated his prior opinion that the water intake system currently under construction may not be operated until the Wisconsin Division of Hearings and Appeals hears any challenge to a reissued or modified permit.

In May 2008, the WDNR issued a draft modified WPDES permit authorizing use of the once-through cooling system under construction for both the expansion units and the existing units at Oak Creek. The public information hearing was held on June 9, 2008 and the public comment period closed on June 16, 2008. On July 31, 2008, the WDNR issued the final modified permit, with no substantive changes from the previously issued draft permit. On September 29, 2008, the time period expired for any party to challenge the modified WPDES permit.

On July 31, 2008, we and the other two joint owners of the Oak Creek expansion reached an agreement with Clean Wisconsin, Inc. and Sierra Club, the groups who were opposing the WPDES permit. Under the settlement agreement, these groups agreed to withdraw their opposition to the modified WPDES permit for the existing and expansion units at Oak Creek.

In the agreement with Clean Wisconsin, Inc. and Sierra Club, we committed to contribute our share of $5 million (approximately $4.2 million) towards projects to reduce greenhouse gas emissions. We also agreed (i) for the 25 year period ending 2034, subject to regulatory approval and cost recovery, to contribute our share of up to $4 million per year (approximately $3.3 million) to fund projects to address Lake Michigan water quality, and (ii) subject to regulatory approval and cost recovery, to develop new solar and biomass generation projects. We also agreed to support state legislation to increase the renewable portfolio standard to 10 percent by 2013 and 25 percent by 2025, and to retire 116 MW of coal-fired generation at our Presque Isle Power Plant.

UTILITY RATES AND REGULATORY MATTERS

2008 Pricing

: During 2007, Wisconsin Electric and Wisconsin Gas initiated rate proceedings. Wisconsin Electric asked the PSCW to approve a comprehensive plan which would result in price increases of $648.6 million for its electric customers in Wisconsin. This price increase would be reduced by expected bill credits resulting from the sale of Point Beach. The initial rate filing estimated bill credits of $371.0 million in 2008 and $187.5 million in 2009, resulting in net pricing increases of 7.5% in 2008 and 7.5% in 2009. In addition, Wisconsin Electric requested a 1.8% price increase in 2008 for its gas customers and an approximately 16.0% price increase in 2008 for all steam customers in Milwaukee. Wisconsin Gas filed for a 4.1% price increase in 2008 for its gas customers.

Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with our new PTF plants; recovery of costs associated with transmission; compliance with environmental regulations; continuation of investment in renewable and efficiency programs, including the Blue Sky Green Field wind project; and scheduled recovery of regulatory assets.

On January 17, 2008, the PSCW approved pricing increases for Wisconsin Electric and Wisconsin Gas as follows:

- ♦ $389.1 million (17.2%) in electric rates for Wisconsin Electric - the pricing increase will be offset by $315.9 million in bill credits in 2008 and $240.7 million in bill credits in 2009, resulting in a net increase of $73.2 million (3.2%) and $75.2 million (3.2%), respectively;
- ♦ $4.0 million (0.6%) for natural gas service from Wisconsin Electric;
- ♦ $3.6 million (11.2%) for steam service from Wisconsin Electric; and
- ♦ $20.1 million (2.2%) for natural gas service from Wisconsin Gas.

In addition, the PSCW lowered the return on equity for Wisconsin Electric and Wisconsin Gas from 11.2% to 10.75%. The PSCW also determined that $85.0 million of the Point Beach proceeds should be immediately applied to offset certain regulatory assets.

Wisconsin Electric expects to provide a total of approximately $669.7 million of bill credits to its Wisconsin customers over the three year period ending December 31, 2010.

Michigan Price Increase Request

: On January 31, 2008, Wisconsin Electric filed a rate increase request with the MPSC. This request represents an increase in electric rates of 14.7%, or $22.0 million, to support the growing demand for electricity, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational expenses. During October 2008, we entered into a settlement agreement with the MPSC staff and intervenors for a rate increase of $7.2 million. We expect the MPSC to approve the settlement by the end of 2008 and the rate increase to be effective on January 1, 2009.

2008 Fuel Recovery Request:

On March 13, 2008, Wisconsin Electric filed a rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel costs is being driven primarily by increases in the price of natural gas and the higher cost of transporting coal by rail as a result of increases in the cost of diesel fuel. On April 11, 2008, the PSCW approved an annual increase of $76.9 million (3.3%) in Wisconsin retail electric rates on an interim basis. In July 2008, we received the final rate order, which authorized an additional $42.0 million in rate increases, for a total increase of $118.9 million (5.1%). Any over-collection of fuel surcharge revenue in calendar year 2008 is subject to refund with interest at a rate of 10.75%.

Fuel Cost Adjustment Procedure:

In June 2006, the PSCW opened a docket (01-AC-224) to consider revisions to the existing fuel rules (Chapter PSC 116). Public comments from stakeholders, including regulated utilities, were received by the PSCW. In July 2008, the PSCW ordered a second comment period on a revised rule, and hearings were held in August 2008. The current version of the revised rule recommends modifications to allow for annual plan and reconciliation filings of fuel costs by each regulated utility. In the period between plan and reconciliation, escrow accounting would be used

to record fuel costs outside a plus or minus 2% annual band of the total fuel costs allowed in rates. The proposed rule further recommends that the escrow balance be trued-up annually following the end of each calendar year. We do not expect any action on the fuel rules until the next legislative session which begins in January 2009.

Oak Creek Air Quality Control System Approval:

As anticipated, 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 at an estimated cost of $830 million, including AFUDC. Construction of these emission controls began in late July 2008, and we expect the installation to be completed during 2012. The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree with the EPA. The Citizens Utility Board and Clean Wisconsin Inc., the two groups that opposed controlling Oak Creek Power Plant Units 5-8, petitioned the PSCW for rehearing and reconsideration of its order. The PSCW denied their request. The petitioners did not appeal the PSCW's decision.

Michigan Legislation:

During October 2008, Michigan enacted legislation to make significant changes in regulatory procedures, which will provide for more timely cost recovery. Public Act 286 potentially allows the use of a forward-looking test year in rate cases, and allows us to put interim rates into effect six months after filing a complete case. Rate filings for which an order is not issued within 12 months are deemed approved. In addition, we could seek a certificate of necessity for new investment, and could recover interest on the investment during construction. Public Act 286 also gives the MPSC expanded authority over proposed mergers and acquisitions, and requires action within 180 days of filing. In addition, Public Act 295 calls for the implementation of a renewable portfolio standard of 10% by 2015, and energy optimization (efficiency) targets up to 1% annually by 2015. Public Act 295 specifically calls for current recovery of costs incurred to meet the standards, and provides for ongoing review and revision to assure the measures taken are cost-effective.

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2007 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

WIND GENERATION

In June 2005, we purchased the development rights to a wind farm project (Blue Sky Green Field) from Navitas Energy, Inc. After receiving the necessary approvals and permits we began construction in June 2007. Wind turbine components began arriving at the site during the fourth quarter of 2007, and the project reached commercial operation in May 2008. Land restoration, road repairs and other post construction activities continue. The cost of this project was approximately $295.3 million, including AFUDC, as of September 30, 2008.

In addition, in October 2007 we provided notice to FPL Energy, a subsidiary of FPL, that we were exercising the option we received in connection with the sale of Point Beach to purchase all rights to a new wind farm site, Glacier Hills Wind Park in central Wisconsin. In July 2008, the purchase was completed and we expect the permitting process to begin later this year. During October 2008, we filed a CPCN for the Glacier Hills Wind Park. We currently expect to install wind turbines with approximately 100 to 200 MW of generating capacity, subject to the final site configuration and the turbine equipment selected. We expect the wind turbines to be placed into service by 2012, subject to regulatory approvals and turbine availability.

ELECTRIC TRANSMISSION AND ENERGY MARKETS

MISO:

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

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of RSG charges. FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. In October 2006 and March 2007, we received additional rulings from FERC on these issues. FERC's rulings have been challenged by MISO and numerous other market participants. MISO commenced with the resettlement of the market in accordance with the orders in July 2007. The resettlement was completed in January 2008 and resulted in a net cost increase of $7.8 million to us. Several entities filed formal complaints with FERC on the assessment of these charges. We filed in support of these complaints.

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

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

MISO is in the process of developing a market for two ancillary services, regulation reserves and contingency reserves. In February 2007, MISO filed tariff revisions to include ancillary services. The MISO ancillary services market is expected to begin in January 2009. We currently self-provide both regulation reserves and contingency reserves. In the MISO ancillary services market, we expect that we will buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market is expected to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market is also expected to enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control

.

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2008 through May 31, 2009. The resulting ARR valuation and the secured FTRs should adequately mitigate our transmission congestion risk for the period.

See Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Electric Transmission and Energy Markets in Item 7 of our 2007 Annual Report on Form 10-K for additional information regarding MISO.

ENVIRONMENTAL MATTERS

National Ambient Air Quality Standards:

In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and $PM_{2.5}$. In December 2006, the EPA further revised the $PM_{2.5}$ standard, and in March 2008, the EPA announced its decision to further lower the 8-hour ozone standard.

8-hour Ozone Standard:

In April 2004, the EPA designated 10 counties in southeastern Wisconsin as nonattainment areas for the 8-hour ozone NAAQS. States were required to develop and submit SIPs to the EPA by June 2007 to demonstrate how they intended to comply with the 8-hour ozone NAAQS. Instead of submitting a SIP, Wisconsin submitted a request to redesignate all counties in southeastern Wisconsin to be in attainment with the standard. In addition to the request for redesignation, Wisconsin also adopted a rule that applies to emissions from our power plants in the affected areas of Wisconsin. We believe compliance with the NO_x emission reduction requirements under the Consent Decree will substantially mitigate costs to comply with the EPA's 8-hour ozone NAAQS. In March 2008, the EPA issued a determination that the state of Wisconsin had failed to submit a SIP. We do not anticipate any further requirements to reduce emissions as a result of this finding, but we are unable to predict that outcome until Wisconsin responds to this finding (expected in July 2009) and the EPA subsequently takes a final approval action. In March 2008, the EPA announced its decision to further lower the 8-hour standard. Although additional counties may be designated as non-attainment areas under the revised standard, until those designations become final and until any potential additional rules are adopted, we are unable to predict the impact on the operation of our existing coal-fired generation facilities.

$PM_{2.5}$

Standard: In December 2004, the EPA designated $PM_{2.5}$ non-attainment areas in the country. All counties in Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard and neither Wisconsin nor Michigan issued any additional state regulation that affects the operation of our existing coal-fired generation facilities. In December 2006, a more restrictive federal standard became effective, which may place some counties into non-attainment status. This standard is currently being litigated. Until such time as the states develop rules and submit SIPs to the EPA to demonstrate how they intend to comply with the standard, we are unable to predict the impact of this more restrictive standard on the operation of our existing coal-fired generation facilities or our new PTF generating units being leased by Wisconsin Electric including OC 1, OC 2 and PWGS.

Clean Air Interstate Rule:

The EPA issued the final CAIR in March 2005 to facilitate the states in meeting the 8-hour ozone and $PM_{2.5}$ standards by addressing the regional transport of SO_2 and NO_x. CAIR required NO_x and SO_2 emission reductions in two phases from electric generating units located in a 28-state region within the eastern United States. Wisconsin and Michigan were affected states under CAIR. Overall, CAIR was expected to result in a 70% reduction in SO_2 emissions and a 65% reduction in NO_x emissions from 2002 emission levels. A final CAIR rule was adopted in Wisconsin and Michigan. Subsequently, in July 2008, the U.S. Court of Appeals for the D.C. Circuit issued a ruling to vacate CAIR and remand it to the EPA to promulgate a rule that is consistent with its decision; however, the Court has not yet issued the mandate that would put its ruling into effect. We previously determined that compliance with the NO_x and SO_2 emission reductions requirements under the Consent Decree would substantially mitigate costs to comply with CAIR. We are unable to predict the content or the timing of any future rule that may replace CAIR. We are also unable to predict how the Court's decision will affect Wisconsin's and Michigan's plans to implement the 8-hour ozone standard, the $PM_{2.5}$ standard and Regional Haze.

Clean Air Mercury Rule

: The EPA issued the final CAMR in March 2005, following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR would limit mercury emissions from new and existing coal-fired power plants and cap utility mercury emissions in two phases,

applicable in 2010 and 2018. The caps would limit emissions at approximately 20% and ultimately 70% below today's utility mercury levels.

The federal rule was challenged by a number of states including Wisconsin and Michigan. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR and sent the rule back to EPA for re-consideration. At this time, we cannot predict the timing or impact on our operations of a future federal rule.

In October 2004, the WDNR issued mercury emission control rules that affect electric utilities in Wisconsin. In March 2008, the WDNR proposed changes to the existing state-only mercury rule. In June 2008, the Natural Resources Board approved the proposed rule. The rule has now completed the state legislative review process and is expected to be published before the end of the year. The new rule requires 90% mercury emission reductions from utilities by 2015, or, under a multi-emission option, 70% reductions by 2015, 80% by 2018 and 90% by 2021, provided utilities meet stringent NO_x and SO_2 emission reduction requirements by 2015. The rule requires a 40% emission reduction for the period 2010-2014. Our plan is to maximize mercury reductions from our initial emission control investments. Enhanced mercury reductions from refinements to SO_2 and NO_x controls are expected to be developed over the next several years. Because control technology is under development, it is difficult to estimate what the cost would be to comply with the Wisconsin requirements. We believe the range of possible expenditures could be approximately $50 million to $200 million.

As of January 2008, the MDEQ has also proposed a rule to both implement CAMR and impose state-only requirements for achieving 90% emission reductions in 2015. The MDEQ has revised the draft rule to remove the requirements related to the now vacated CAMR, but is proceeding with the remainder of the state-only rule as proposed. As part of a new technology demonstration which we undertook in partnership with the DOE, technology for the control of mercury has been installed at Presque Isle Power Plant. We plan to continue the operation of that equipment beyond the test period. We anticipate that this equipment will be sufficient to comply with reductions that would be required under the state-only rule.

Clean Air Visibility Rule:

The EPA issued CAVR in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to the EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States are then required to determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia. States were required to submit plans to implement CAVR to the EPA by December 2007. The reductions associated with the state plans are scheduled to begin to take effect in 2014, with full implementation before 2018. Wisconsin has not yet submitted a plan. Michigan proposed an initial plan in October 2007 and a revised plan in September 2008. Michigan's draft plan does not require additional emission reductions from our existing or new coal-fired generating facilities. Wisconsin and Michigan have completed the BART rules, which cover one aspect of CAVR regulations. Wisconsin BART rules became effective in July 2008. Michigan BART rules became effective in September 2008.

Both Wisconsin and Michigan BART rules are based, in part, on utility reductions of NO_x and SO_2 that were expected to occur under CAIR. Therefore, we are uncertain how the recent court decision on CAIR and any possible court-related, EPA or Congressional actions taken in response to the court decision will impact Wisconsin's and Michigan's implementation of BART rules, and subsequent requirements on our system. Environmental agencies in both states have yet to make final determinations regarding BART implementation affecting utilities. The state BART rules include December 31, 2012 and 2013 compliance dates in Michigan and Wisconsin, respectively.

EPA Advance Notice of Proposed Rulemaking:

In July 2008, the EPA issued an Advance Notice of Proposed Rulemaking seeking comment on a large array of possible regulatory actions it is contemplating under the federal Clean Air Act to reduce greenhouse gas emissions. The proposed rules impact virtually all aspects of the economy including electric and natural gas utilities. The EPA document follows a U.S. Supreme Court decision last year requiring the EPA to regulate greenhouse gas emissions under the Clean Air Act if it finds that they endanger public health or welfare. The document seeks comment on whether the EPA should make that finding and, if so, the types of regulations it should adopt. There is a 120 day comment period.

We cannot predict at this time what impact, if any, such a finding would have on us.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2007 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For information concerning market risk exposures at Wisconsin Energy Corporation, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 2007 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures:

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based upon such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting:

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

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2007 Annual Report on Form 10-K.

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

UTILITY RATES AND REGULATORY MATTERS

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

Power the Future:

See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Part I of this report for information concerning our PTF strategy.

ITEM 1A. RISK FACTORS

See Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three-month period ended September 30, 2008:

2008	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(Millions of Dollars)
July 1- July 31	945	$45.12	-	$ -

August 1-August 31	-	$ -	-	$ -
September 1-September 30	-	$ -	-	$ -
Total	945	$45.12	-	$ -

(a) This table does not include shares purchased by independent agents to satisfy obligations under our employee benefit plans and stock purchase and dividend reinvestment plan. All shares reported during the quarter were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

ITEM 5. OTHER INFORMATION

On October 29, 2008, the Compensation Committee of the Board of Directors of Wisconsin Energy Corporation authorized and approved amendments to certain executive compensation arrangements for its named executive officers and directors in order to bring such arrangements into documentary compliance with Section 409A of the Internal Revenue Code of 1986, as amended, and corresponding regulations (collectively, "Section 409A"). The amendments are generally technical in nature and affect the timing, but not the amount, of benefits payable to the named executive officers or directors.

As part of the actions taken by the Compensation Committee, the Wisconsin Energy Corporation Executive Deferred Compensation Plan (the "Legacy EDCP"), the Wisconsin Energy Corporation Directors' Deferred Compensation Plan (the "Legacy DDCP") and the Wisconsin Energy Corporation Supplemental Executive Retirement Plan (the "Legacy SERP") were renamed and amended effective as of January 1, 2005 to (i) provide that amounts earned, deferred, vested, credited and/or accrued under such plans as of December 31, 2004 are preserved and frozen so that such amounts are exempt from Section 409A, and (ii) provide that no new employees (or directors for the Legacy DDCP) may participate in these plans as of January 1, 2005. The Compensation Committee also adopted new deferred compensation plans effective as of January 1, 2005 which offer features substantially similar to the Legacy EDCP, Legacy DDCP and Legacy SERP, but with the changes necessary to comply with Section 409A.

In addition, the following plans and agreements were also amended and restated as of the dates indicated below to bring them into documentary compliance with Section 409A:

- Wisconsin Energy Corporation Short-Term Performance Plan (effective January 1, 2005);

- Amended and Restated Wisconsin Energy Corporation Executive Severance Policy (effective January 1, 2005);
- Wisconsin Energy Corporation Omnibus Stock Incentive Plan (effective January 1, 2005);
- Wisconsin Energy Corporation Performance Unit Plan (effective January 1, 2005);
- Amended and Restated Senior Officer and Non-Compete Agreement between Wisconsin Energy Corporation and Gale E. Klappa (effective January 1, 2005);
- Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett (effective January 1, 2005);
- Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Rick Kuester (effective January 1, 2005);
- Letter Agreement by and between Wisconsin Energy Corporation and James C. Fleming (effective November 23, 2005); and
- Amended and Restated Senior Officer, Change in Control, Severance and Non-Compete Agreement between Wisconsin Energy Corporation and Kristine A. Rappé (effective January 1, 2008).

ITEM 6. EXHIBITS

<u>Exhibit No.</u>

4	Instruments defining the rights of security holders, including indentures
4.1	Securities Resolution No. 8 of Wisconsin Electric, dated as of September 25, 2008, under the Indenture for Debt Securities, dated as of December 1, 1995, between Wisconsin Electric and U.S. Bank National Association (as successor to Firstar Trust Company), as Trustee. (Exhibit 4.1 to Wisconsin Electric's 09/25/08 Form 8-K.)
12	Statements re computation of ratios
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
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.

99 Additional exhibits

99.1* Turnkey Engineering, Procurement and Construction Contract for Supercritical Pulverized Coal Fired Electric Generation Facility between Elm Road Services, LLC and Bechtel Power Corporation, dated April 19, 2004, as amended (the "EPC Contract").

99.2 Change Order No. 8 to the EPC Contract.

99.3 Change Order No. 12A to the EPC Contract.

99.4 Change Order No. 12b to the EPC Contract.

* Wisconsin Energy has requested confidential treatment of certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Wisconsin Energy has omitted such portions from this filing and filed them separately with the SEC.

SIGNATURES

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

WISCONSIN ENERGY CORPORATION
(Registrant)

/s/STEPHEN P. DICKSON

Date: October 30, 2008

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