NAUTILUS, INC.
Form 10-Q
November 09, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2012

or

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

For the transition period from to

Commission file number: 001-31321

NAUTILUS, INC.
(Exact name of Registrant as specified in its charter)

Washington (State or other jurisdiction of incorporation or organization)	94-3002667 (I.R.S. Employer Identification No.)

16400 S.E. Nautilus Drive
Vancouver, Washington 98683
(Address of principal executive offices, including zip code)
(360) 859-2900
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [x]
(do not check if a 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:

The number of shares outstanding of the registrant's common stock as of October 31, 2012 was 30,908,420 shares.

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements
NAUTILUS, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited and in thousands)

	As of September 30, 2012	December 31, 2011
ASSETS		
Cash and cash equivalents	$15,209	$17,427
Trade receivables, net of allowances of $176 as of September 30, 2012 and $300 as of December 31, 2011	11,735	23,780
Inventories	16,900	11,601
Prepaids and other current assets	4,482	4,433
Income taxes receivable	582	454
Short-term notes receivable	163	317
Deferred income tax assets	86	75
Total current assets	49,157	58,087
Property, plant and equipment, net	5,811	4,405
Goodwill	2,979	2,873
Other intangible assets, net	15,178	16,716
Other assets	711	732
Total assets	$73,836	$82,813
LIABILITIES AND STOCKHOLDERS' EQUITY		
Trade payables	$21,117	$28,563
Accrued liabilities	7,110	7,218
Warranty obligations, current portion	1,848	1,803
Deferred income tax liabilities	1,158	1,064
Total current liabilities	31,233	38,648
Long-term notes payable	—	5,598
Warranty obligations, non-current	214	214
Income taxes payable, non-current	2,891	3,658
Deferred income tax liabilities, non-current	1,660	1,434
Other long-term liabilities	2,057	1,308
Total liabilities	38,055	50,860
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Common stock - no par value, 75,000 shares authorized, 30,896 and 30,747 shares issued and outstanding as of September 30, 2012 and December 31, 2011, respectively	5,901	5,360
Retained earnings	23,023	19,715
Accumulated other comprehensive income	6,857	6,878
Total stockholders' equity	35,781	31,953
Total liabilities and stockholders' equity	$73,836	$82,813

See accompanying notes to condensed consolidated financial statements.

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NAUTILUS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited and in thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Net sales	$38,052	$ 37,402	$128,897	$120,427
Cost of sales	19,511	21,605	69,283	68,000
Gross profit	18,541	15,797	59,614	52,427
Operating expenses:				
Selling and marketing	12,434	11,517	41,057	38,601
General and administrative	4,371	4,134	12,672	13,103
Research and development	1,038	859	2,957	2,336
Total operating expenses	17,843	16,510	56,686	54,040
Operating income (loss)	698	(713)	2,928	(1,613)
Other income (expense):				
Interest income	3	5	16	14
Interest expense	(9)	(116)	66	(348)
Other	(101)	(65)	(187)	17
Total other expense	(107)	(176)	(105)	(317)
Income (loss) from continuing operations before income taxes	591	(889)	2,823	(1,930)
Income tax benefit	(625) September 2013	6 Wisconsin Energy Corporation		

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

INTRODUCTION

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

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

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our Power the Future (PTF) strategy. See Item 1. Business and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2012 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 2012 Annual Report on Form 10-K, including the financial statements and notes therein.

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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	
	2013	2012	2013	2012
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$1,053.2	$1,039.3	$3,340.7	$3,175.2
Operating Expenses				
Fuel and purchased power	339.1	336.4	886.2	848.9
Cost of gas sold	61.6	55.5	446.9	368.0
Other operation and maintenance	268.1	244.6	821.6	798.8
Depreciation and amortization	96.9	91.8	289.1	269.7
Property and revenue taxes	29.5	30.4	88.4	90.9
Total Operating Expenses	795.2	758.7	2,532.2	2,376.3
Operating Income	258.0	280.6	808.5	798.9
Equity in Earnings of Transmission Affiliate	17.1	17.1	51.0	48.9
Other Income, net	5.1	9.0	15.3	33.6
Interest Expense, net	62.0	60.9	190.3	181.3
Income Before Income Taxes	218.2	245.8	684.5	700.1
Income Tax Expense	80.7	89.7	251.4	252.6
Net Income	$137.5	$156.1	$433.1	$447.5
Earnings Per Share				
Basic	$0.61	$0.68	$1.90	$1.94
Diluted	$0.60	$0.67	$1.88	$1.92
Weighted Average Common Shares Outstanding (Millions)				
Basic	226.8	230.4	228.0	230.4
Diluted	228.8	232.9	230.2	233.1
Dividends Per Share of Common Stock	$0.3825	$0.30	$1.0625	$0.90

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

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WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$14,530.6	$14,238.8
Accumulated depreciation	(4,202.0)	(4,036.0)
	10,328.6	10,202.8
Construction work in progress	427.4	315.9
Leased facilities, net	49.2	53.5
Net Property, Plant and Equipment	10,805.2	10,572.2
Investments		
Equity investment in transmission affiliate	396.7	378.3
Other	36.5	35.5
Total Investments	433.2	413.8
Current Assets		
Cash and cash equivalents	18.5	35.6
Accounts receivable, net	299.0	285.3
Accrued revenues	161.0	278.1
Materials, supplies and inventories	367.6	360.7
Current deferred tax asset, net	230.8	46.3
Prepayments and other	161.3	307.9
Total Current Assets	1,238.2	1,313.9
Deferred Charges and Other Assets		
Regulatory assets	1,267.4	1,339.0
Goodwill	441.9	441.9
Other	186.9	204.2
Total Deferred Charges and Other Assets	1,896.2	1,985.1
Total Assets	$14,372.8	$14,285.0
Capitalization and Liabilities		
Capitalization		
Common equity	$4,198.1	$4,135.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,370.9	4,453.8
Total Capitalization	8,599.4	8,619.3
Current Liabilities		
Long-term debt due currently	371.0	412.1
Short-term debt	361.8	394.6
Accounts payable	296.9	368.4
Accrued payroll and benefits	90.8	100.9
Other	170.7	167.3
Total Current Liabilities	1,291.2	1,443.3
Deferred Credits and Other Liabilities		
Regulatory liabilities	830.7	866.5
Deferred income taxes - long-term	2,470.3	2,117.0

Deferred revenue, net	676.8	709.7
Pension and other benefit obligations	214.5	244.0
Other	289.9	285.2
Total Deferred Credits and Other Liabilities	4,482.2	4,222.4
Total Capitalization and Liabilities	$14,372.8	$14,285.0

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

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

	Nine Months Ended September 30	
	2013	2012
	(Millions of Dollars)	
Operating Activities		
Net income	$433.1	$447.5
Reconciliation to cash		
Depreciation and amortization	297.6	278.2
Deferred income taxes and investment tax credits, net	219.8	249.6
Contributions to qualified benefit plans	—	(100.0)
Change in - Accounts receivable and accrued revenues	95.3	118.7
Inventories	(6.9)	39.9
Other current assets	40.6	50.6
Accounts payable	(59.2)	(56.5)
Accrued income taxes, net	48.2	107.6
Other current liabilities	(0.1)	(15.3)
Other, net	(18.1)	(127.9)
Cash Provided by Operating Activities	1,050.3	992.4
Investing Activities		
Capital expenditures	(497.7)	(477.5)
Investment in transmission affiliate	(7.9)	(13.1)
Change in restricted cash	2.7	36.0
Other, net	(41.9)	(36.8)
Cash Used in Investing Activities	(544.8)	(491.4)
Financing Activities		
Exercise of stock options	42.7	45.3
Purchase of common stock	(187.9)	(105.0)
Dividends paid on common stock	(242.3)	(207.4)
Issuance of long-term debt	251.0	—
Retirement of long-term debt	(364.2)	(18.3)
Change in short-term debt	(32.8)	(216.7)
Other, net	10.9	—
Cash Used in Financing Activities	(522.6)	(502.1)
Change in Cash and Cash Equivalents	(17.1)	(1.1)
Cash and Cash Equivalents at Beginning of Period	35.6	14.1
Cash and Cash Equivalents at End of Period	$18.5	$13.0

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

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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 2012 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and nine months ended September 30, 2013 are not necessarily indicative of the results which may be expected for the entire fiscal year 2013 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Offsetting Assets and Liabilities: In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2011-11, Disclosures about Offsetting Assets and Liabilities. The guidance requires enhanced disclosures about derivatives. Both gross and net information related to eligible transactions is required under the guidance. This guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013, and must be applied retrospectively. We adopted this guidance on January 1, 2013, and applied it retrospectively. The adoption and retrospective application of this guidance did not have any material impact on our financial statements. See Note 6 -- Derivative Instruments for the enhanced disclosures.

3 -- COMMON EQUITY -

Stock Option Activity: The following table identifies non-qualified stock options granted by the Compensation Committee of the Board of Directors (Compensation Committee):

	2013		2012	
Non-qualified stock options granted year to date	1,418,560		938,770	
Estimated fair value per non-qualified stock option	$3.45		$3.34	
Assumptions used to value the options using a binomial option pricing model:				
Risk-free interest rate	0.1% - 1.9%		0.1% - 2.0%	
Dividend yield	3.7	%	3.9	%
Expected volatility	18.0	%	19.0	%
Expected forfeiture rate	2.0	%	2.0	%
Expected life (years)	5.9		5.9	

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

The following is a summary of our stock option activity for the three and nine months ended September 30, 2013:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of July 1, 2013	8,484,258	$26.53		
Granted	—	$—		
Exercised	(91,096)	$21.75		
Forfeited	(4,680)	$35.36		
Outstanding as of September 30, 2013	8,388,482	$26.58		
Outstanding as of January 1, 2013	8,919,669	$23.86		
Granted	1,418,560	$37.46		
Exercised	(1,939,717)	$21.99		
Forfeited	(10,030)	$35.37		
Outstanding as of September 30, 2013	8,388,482	$26.58	5.5	$115.8
Exercisable as of September 30, 2013	6,007,692	$22.98	4.2	$104.5

The intrinsic value of options exercised was $1.9 million and $37.9 million for the three and nine months ended September 30, 2013, and $8.3 million and $42.1 million for the same periods in 2012, respectively. Cash received from options exercised was $42.7 million and $45.3 million for the nine months ended September 30, 2013 and 2012, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was $15.1 million and zero, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the third quarter of 2013.

The following table summarizes information about stock options outstanding as of September 30, 2013:

	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)
$16.72 to $21.11	2,418,982	$20.23	3.9	2,418,982	$20.23	3.9
$23.88 to $29.35	3,698,060	$24.65	4.5	3,390,790	$24.23	4.2
$34.87 to $37.46	2,271,440	$36.48	8.9	197,920	$35.19	8.4
	8,388,482	$26.58	5.5	6,007,692	$22.98	4.2

The following table summarizes information about our non-vested options during the three and nine months ended September 30, 2013:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of July 1, 2013	2,394,085	$3.38
Granted	—	$—
Vested	(8,615)	$3.36
Forfeited	(4,680)	$3.37
Non-vested as of September 30, 2013	2,380,790	$3.38
Non-vested as of January 1, 2013	1,702,275	$3.31
Granted	1,418,560	$3.45
Vested	(730,015)	$3.34
Forfeited	(10,030)	$3.37
Non-vested as of September 30, 2013	2,380,790	$3.38

As of September 30, 2013, total compensation costs related to non-vested stock options not yet recognized was approximately $3.0 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Restricted Shares: The following restricted stock activity occurred during the three and nine months ended September 30, 2013:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of July 1, 2013	151,271	
Granted	—	$—
Released	—	$—
Forfeited	(573)	$34.96
Outstanding as of September 30, 2013	150,698	
Outstanding as of January 1, 2013	188,222	
Granted	74,290	$37.65
Released	(97,973)	$26.65
Forfeited	(13,841)	$33.35
Outstanding as of September 30, 2013	150,698	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was zero and $4.0 million for the three and nine months ended September 30, 2013, and zero and $3.3 million for the same periods in 2012, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero and $1.3 million for the three and nine months ended September 30, 2013, and zero for the same periods in 2012, respectively.

As of September 30, 2013, total compensation cost related to restricted stock not yet recognized was approximately $3.2 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

Performance Units: In January 2013 and 2012, the Compensation Committee granted 239,120 and 346,570 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Performance units earned as of December 31, 2012 and 2011 vested and were settled during the first quarter of

2013 and 2012, and had a total intrinsic value of $19.3 million and $26.7 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $7.0 million and $9.7 million, respectively. As of September 30, 2013, total compensation cost related to performance units not yet recognized was approximately $13.1 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note H -- Common Equity in our 2012 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.

Share Repurchase Program: In May 2011, our Board of Directors authorized a share repurchase program that allows us to repurchase up to $300 million of our common stock through the end of 2013. Through September 30, 2013, we have repurchased $254.8 million of our common stock pursuant to this program at an average cost of $35.78 per share. The share repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company in the following periods:

	Nine Months Ended September 30			
	2013		2012	
	Shares	Cost	Shares	Cost
	(In Millions)			
Under May 2011 share repurchase program	2.5	$103.0	0.4	$14.0
To fulfill exercised stock options and restricted stock awards	2.1	84.9	2.5	91.0
Total	4.6	$187.9	2.9	$105.0

4 -- LONG-TERM DEBT

On September 15, 2013, Wisconsin Gas used short-term borrowings to retire $45 million of long-term debt that matured.

In June 2013, Wisconsin Electric issued $250 million of 1.70% Debentures due June 15, 2018. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other corporate purposes.

On May 15, 2013, Wisconsin Electric used short-term borrowings to retire $300 million of long-term debt that matured.

5 -- FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

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

Recurring Fair Value Measures	As of September 30, 2013			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$—	$—	$—	$—
Derivatives	2.4	4.4	5.6	12.4
Total	$2.4	$4.4	$5.6	$12.4
Liabilities:				
Derivatives	$1.7	$0.4	$—	$2.1
Total	$1.7	$0.4	$—	$2.1

Recurring Fair Value Measures	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$2.7	$—	$—	$2.7
Derivatives	2.2	12.3	4.7	19.2
Total	$4.9	$12.3	$4.7	$21.9
Liabilities:				
Derivatives	$1.9	$—	$—	$1.9
Total	$1.9	$—	$—	$1.9

We adopted ASU 2011-11, Disclosures about Offsetting Assets and Liabilities, on a retrospective basis. For additional information, see Note 2 -- New Accounting Pronouncements and Note 6 -- Derivative Instruments.

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which was returned, net of costs incurred, to customers. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	2012	2013	2012
	(Millions of Dollars)			
Beginning Balance	$9.2	$9.9	$4.7	$5.7
Realized and unrealized gains (losses)	—	—	—	—
Purchases	—	—	10.6	10.9
Issuances	—	—	—	—
Settlements	(3.6)	(2.6)	(9.7)	(9.3)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of September 30	$5.6	$7.3	$5.6	$7.3
Change in unrealized gains (losses) relating to instruments still held as of September 30	$—	$—	$—	$—

Derivative instruments reflected in Level 3 of the hierarchy include MISO Financial Transmission Rights (FTRs) that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note 6 -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

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

Financial Instruments	September 30, 2013 Carrying Amount	Fair Value	December 31, 2012 Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$26.3	$30.4	$26.0
Long-term debt, including current portion	$4,659.7	$4,951.7	$4,772.9	$5,447.3

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

6 -- DERIVATIVE INSTRUMENTS

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

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of September 30, 2013, we recognized $4.9 million in regulatory assets and $10.5 million in regulatory liabilities related to derivatives in comparison to $7.6 million in regulatory assets and $17.5 million in regulatory liabilities as of December 31, 2012.

We record our current derivative assets on the balance sheet in prepayments and other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.8 million is recorded in other deferred charges and other assets as of September 30, 2013, and the long-term portion of our derivative liabilities of $0.2 million is recorded in other deferred credits and other liabilities as of September 30, 2013. Our Consolidated Condensed Balance Sheets as of September 30, 2013 and December 31, 2012 include:

	September 30, 2013		December 31, 2012	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$3.1	$2.1	$3.0	$1.9
Fuel Oil	0.3	—	0.4	—
FTRs	5.6	—	4.7	—
Coal	3.4	—	11.1	—
Total	$12.4	$2.1	$19.2	$1.9

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) were as follows:

	Three Months Ended September 30, 2013		Three Months Ended September 30, 2012	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	6.3 million Dth	$(1.1)	17.2 million Dth	$(5.3)
Fuel Oil	2.5 million gallons	(0.1)	1.7 million gallons	0.1
FTRs	6,322 MW	5.4	5,927 MW	2.9
Total		$4.2		$(2.3)

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	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	36.4 million Dth	$(5.7)	56.0 million Dth	$(35.7)
Fuel Oil	6.2 million gallons	0.1	5.5 million gallons	1.5
FTRs	17,410 MW	11.0	16,581 MW	5.1
Total		$5.4		$(29.1)

As of September 30, 2013 and December 31, 2012, we posted collateral of $2.6 million and $2.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

The fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. The table below shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on the balance sheet as of September 30, 2013 and December 31, 2012.

	September 30, 2013		December 31, 2012	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Gross Amount Recognized on the Balance Sheet	$12.4	$2.1	$19.2	$1.9
Gross Amount Not Offset on Balance Sheet (a)	(0.3)	(1.7)	(0.5)	(1.8)
Net Amount	$12.1	$0.4	$18.7	$0.1

(a) Gross Amount Not Offset on Balance Sheet includes cash collateral posted of $1.5 million and $1.3 million as of September 30, 2013 and December 31, 2012, respectively.

7 -- BENEFITS

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

	Pension Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
Benefit Plan Cost Components	2013	2012	2013	2012
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$3.7	$5.5	$11.0	$16.3
Interest cost	15.1	16.4	45.3	49.2
Expected return on plan assets	(23.9)	(22.5)	(71.8)	(67.3)
Amortization of:				
Prior service cost	0.5	0.5	1.7	1.7
Actuarial loss	13.6	10.2	40.8	30.4

Net Periodic Benefit Cost	$9.0	$10.1	$27.0	$30.3

Benefit Plan Cost Components	OPEB Costs Three Months Ended September 30 2013	2012	Nine Months Ended September 30 2013	2012
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.5	$2.6	$7.5	$7.8
Interest cost	3.9	5.1	11.7	15.3
Expected return on plan assets	(5.4)	(4.8)	(16.0)	(14.4)
Amortization of:				
Transition obligation	—	—	—	0.2
Prior service (credit)	(0.5)	(0.5)	(1.5)	(1.4)
Actuarial loss	1.0	1.9	2.8	5.4
Net Periodic Benefit Cost	$1.5	$4.3	$4.5	$12.9

During the first nine months of 2013 and 2012, we contributed zero and $100.0 million, respectively, to our qualified benefit plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $4.0 million as of September 30, 2013 and December 31, 2012.

8 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable segments for the three and nine months ended September 30, 2013 and 2012 is shown in the following table:

Three Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
September 30, 2013					
Operating Revenues (b)	$1,037.2	$114.2	$0.4	$(98.6)	$1,053.2
Other Operation and Maintenance	$359.5	$4.2	$1.9	$(97.5)	$268.1
Depreciation and Amortization	$79.9	$16.8	$0.2	$—	$96.9
Operating Income (Loss)	$166.6	$93.2	$(1.8)	$—	$258.0
Equity in Earnings of Unconsolidated Affiliates	$17.1	$—	$—	$—	$17.1
Interest Expense, Net	$33.0	$16.4	$12.8	$(0.2)	$62.0
Income Tax Expense (Benefit)	$56.1	$29.5	$(4.9)	$—	$80.7
Net Income (Loss)	$99.3	$47.4	$137.4	$(146.6)	$137.5
Capital Expenditures	$178.1	$10.4	$1.9	$—	$190.4
September 30, 2012					
Operating Revenues (b)	$1,023.3	$112.6	$0.3	$(96.9)	$1,039.3
Other Operation and Maintenance	$334.1	$4.3	$2.0	$(95.8)	$244.6
Depreciation and Amortization	$74.7	$16.8	$0.3	$—	$91.8

Operating Income (Loss)	$191.0	$91.5	$(1.9)	$—	$280.6
Equity in Earnings of Unconsolidated Affiliates	$17.1	$—	$—	$—	$17.1
Interest Expense, Net	$31.4	$16.6	$12.9	$—	$60.9
Income Tax Expense (Benefit)	$65.6	$29.2	$(5.1)	$—	$89.7
Net Income (Loss)	$119.8	$45.8	$156.1	$(165.6)	$156.1
Capital Expenditures	$161.2	$1.8	$0.5	$—	$163.5

Nine Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
September 30, 2013					
Operating Revenues (b)	$3,296.7	$337.3	$1.0	$(294.3)	$3,340.7
Other Operation and Maintenance	$1,097.7	$10.6	$4.1	$(290.8)	$821.6
Depreciation and Amortization	$238.2	$50.3	$0.6	$—	$289.1
Operating Income (Loss)	$536.1	$276.4	$(4.0)	$—	$808.5
Equity in Earnings of Unconsolidated Affiliates	$51.0	$—	$—	$—	$51.0
Interest Expense, Net	$103.1	$49.4	$38.2	$(0.4)	$190.3
Income Tax Expense (Benefit)	$179.9	$90.1	$(18.6)	$—	$251.4
Net Income (Loss)	$317.9	$137.2	$432.9	$(454.9)	$433.1
Capital Expenditures	$476.2	$17.5	$4.0	$—	$497.7
September 30, 2012					
Operating Revenues (b)	$3,132.2	$332.2	$0.9	$(290.1)	$3,175.2
Other Operation and Maintenance	$1,069.0	$11.7	$4.7	$(286.6)	$798.8
Depreciation and Amortization	$218.8	$50.3	$0.6	$—	$269.7
Operating Income (Loss)	$533.2	$270.2	$(4.5)	$—	$798.9
Equity in Earnings of Unconsolidated Affiliates	$48.9	$—	$(0.1)	$—	$48.8
Interest Expense, Net	$92.6	$50.1	$38.9	$(0.3)	$181.3
Income Tax Expense (Benefit)	$182.6	$87.2	$(17.2)	$—	$252.6
Net Income (Loss)	$338.7	$133.2	$448.0	$(472.4)	$447.5
Capital Expenditures	$468.2	$5.6	$3.7	$—	$477.5

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

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

9 -- VARIABLE INTEREST ENTITIES

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

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

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

We have approximately $226.0 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under contracts considered variable interests for the nine months ended September 30, 2013 and

2012 were $37.8 million and $44.5 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

10 -- COMMITMENTS AND CONTINGENCIES

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

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

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $16 million to $62 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of September 30, 2013, we have established reserves of $38.2 million related to future remediation costs.

Historically, the PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Divested Assets: Pursuant to the sale of the Point Beach Nuclear Power Plant, we agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. in connection with the sale of our interest in Edgewater Generating Unit 5.

11 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2013, we paid $146.6 million in interest, net of amounts capitalized, and received $38.3 million in net refunds from income taxes. During the nine months ended September 30, 2012, we paid $137.9 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes.

As of September 30, 2013 and 2012, the amount of accounts payable related to capital expenditures was $3.4 million and $25.3 million, respectively.

During the nine months ended September 30, 2013 and 2012, total amortization of deferred revenue was $42.7 million and $41.2 million, respectively.

During the nine months ended September 30, 2013 and 2012, our equity in earnings from ATC was $51.0 million and $48.9 million, respectively. During the nine months ended September 30, 2013 and 2012, distributions received from ATC were $40.5 million and $39.0 million, respectively.

Form 10-Q

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED SEPTEMBER 30, 2013

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the third quarter of 2013 with the third quarter of 2012, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars, Except Per Share Amounts)		
Utility Energy Segment	$166.6	$(24.4)	$191.0
Non-Utility Energy Segment	93.2	1.7	91.5
Corporate and Other	(1.8)	0.1	(1.9)
Total Operating Income	258.0	(22.6)	280.6
Equity in Earnings of Transmission Affiliate	17.1	—	17.1
Other Income, net	5.1	(3.9)	9.0
Interest Expense, net	62.0	(1.1)	60.9
Income Before Income Taxes	218.2	(27.6)	245.8
Income Tax Expense	80.7	9.0	89.7
Net Income	$137.5	$(18.6)	$156.1
Diluted Earnings Per Share	$0.60	$(0.07)	$0.67

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $166.6 million of operating income during the third quarter of 2013, a decrease of $24.4 million, or 12.8%, compared with the third quarter of 2012. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended September 30		
Utility Energy Segment	2013	B (W)	2012
	(Millions of Dollars)		
Operating Revenues			
Electric	$911.0	$9.8	$901.2
Gas	120.6	3.9	116.7
Other	5.6	0.2	5.4
Total Operating Revenues	1,037.2	13.9	1,023.3
Operating Expenses			
Fuel and Purchased Power	340.4	(2.7)	337.7
Cost of Gas Sold	61.6	(6.1)	55.5
Other Operation and Maintenance	359.5	(25.4)	334.1
Depreciation and Amortization	79.9	(5.2)	74.7
Property and Revenue Taxes	29.2	1.1	30.3

Total Operating Expenses	870.6	(38.3)	832.3
Operating Income	$166.6	$(24.4)	$191.0

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Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the third quarter of 2013 with the third quarter of 2012:

	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2013	B (W)	2012	2013	B (W)	2012
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$332.7	$(7.5)	$340.2	2,207.7	(214.8)	2,422.5
Small Commercial/Industrial	287.9	3.7	284.2	2,381.6	(74.7)	2,456.3
Large Commercial/Industrial	200.2	(0.5)	200.7	2,326.3	(159.8)	2,486.1
Other - Retail	5.5	0.1	5.4	34.6	—	34.6
Total Retail	826.3	(4.2)	830.5	6,950.2	(449.3)	7,399.5
Wholesale - Other	32.6	(7.4)	40.0	405.8	(5.9)	411.7
Resale - Utilities	45.4	27.6	17.8	1,430.2	833.9	596.3
Other Operating Revenues	6.7	(6.2)	12.9	—	—	—
Total	$911.0	$9.8	$901.2	8,786.2	378.7	8,407.5
Weather -- Degree Days (a)						
Heating (124 Normal)				130	(8)	138
Cooling (549 Normal)				540	(195)	735

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

Our electric utility operating revenues increased by $9.8 million, or 1.1%, when compared to the third quarter of 2012. The most significant factors that caused a change in revenues were:

- Wisconsin net retail pricing increases of $31.8 million ($48.7 million less $16.9 million related to Section 1603 bill credits), which is primarily related to our 2013 Wisconsin Rate Case. For information on the Section 1603 bill credits and the rate order in the 2013 rate case, see Results of Operations -- Three Months Ended September 30, 2013 -- Section 1603 Renewable Energy Treasury Grant and Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters, respectively.
- A return to more normal weather in the third quarter of 2013 as compared to the same period in 2012 that decreased electric revenues by an estimated $31.9 million.
- A $27.6 million increase in sales for resale due to increased sales into the MISO Energy Markets as a result of increased availability of our generating units.
- A $7.4 million decrease in wholesale revenues in the third quarter of 2013 primarily due to reduced demand revenue as compared to the same period in 2012.
- A $6.2 million decrease in other operating revenues, primarily driven by the amortization of $8.0 million in 2012 related to the settlement with the DOE. See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2012 Fuel Recovery Request.

As measured by cooling degree days, the third quarter of 2013 was 26.5% cooler than the same period in 2012 and 1.6% cooler than normal. We believe the cooler weather was the primary reason for the 8.9% decrease in residential sales. Sales to large commercial/industrial customers decreased by 6.4%, primarily because of a decrease in sales to the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 3.5%.

The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. See Factors Affecting Results, Liquidity and Capital Resources - Electric Transmission and Energy Markets - Restructuring in Michigan, for a discussion of the impact of industry restructuring in Michigan on our electric sales.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $2.7 million, or 0.8%, when compared to the third quarter of 2012. This increase was primarily caused by a 4.5% increase in total MWh sales, partially offset by lower costs as compared to the third quarter of 2012.

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 2013 with the third quarter of 2012. 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 $3.9 million, or 3.3%, and cost of gas sold increased by $6.1 million, or 11.0%, due to an increase in the commodity cost of natural gas.

	Three Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Gas Operating Revenues	$120.6	$3.9	$116.7
Cost of Gas Sold	61.6	(6.1)	55.5
Gross Margin	$59.0	$(2.2)	$61.2

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the third quarter of 2013 with the third quarter of 2012:

	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2013	B (W)	2012	2013	B (W)	2012
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$37.4	$(0.5)	$37.9	47.2	1.0	46.2
Commercial/Industrial	9.4	(0.8)	10.2	33.3	0.2	33.1
Interruptible	0.3	—	0.3	2.8	0.5	2.3
Total Retail	47.1	(1.3)	48.4	83.3	1.7	81.6
Transported Gas	10.9	(0.9)	11.8	236.0	(33.7)	269.7
Other	1.0	—	1.0	—	—	—
Total	$59.0	$(2.2)	$61.2	319.3	(32.0)	351.3
Weather -- Degree Days (a)						
Heating (124 Normal)				130	(8)	138

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

Our gas margin is seasonal and is primarily driven by the heating needs of our customers. The third quarter gas margin is historically the lowest of the year because of the lack of heating load. Our gas margin decreased by $2.2 million, or approximately 3.6%, when compared to the third quarter of 2012. Gas margins were reduced by approximately $2.4

million because of lower gas rates that became effective January 1, 2013.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by $25.4 million, or approximately 7.6%, when compared to the third quarter of 2012. This increase was primarily driven by the reinstatement of $37.0 million of regulatory amortizations, offset in part by a $8.2 million reduction in bad debt expense related to our natural gas customers and continued cost control efforts across the utility.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $5.2 million, or approximately 7.0%, when compared to the third quarter of 2012 primarily because of an overall increase in utility plant in service. The emission control equipment for units 7 and 8 of the Oak Creek Air Quality Control System (AQCS) project went into service in September 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

Section 1603 Renewable Energy Treasury Grant

We expect to receive a treasury grant of approximately $72 million related to the construction of our biomass facility in Rothschild, Wisconsin. The PSCW took this grant into consideration when it set rates for our electric customers for the two years ending December 31, 2014. These rates became effective on January 1, 2013 and are reflected in the form of bill credits that reduce our revenues. We expect to recognize the treasury grant as income in the fourth quarter of 2013 when the plant is expected to be placed into service. At that time, we will also defer as a regulatory liability, the portion of the grant income that will be used to reduce rates in 2014. For the first three quarters of 2013, we experienced a mismatch between bill credits (lower revenues) and grant income. However, when the plant is placed into service in the fourth quarter, we will make an entry to record grant income to match the bill credits that have been provided to customers during 2013. If we recorded grant income to match the credits provided to customers, we estimate that the earnings in the first, second and third quarters would have been approximately $0.03 per share higher in each quarter.

In addition, the PSCW approved escrow accounting treatment for the treasury grant. As a result, we expect to true-up any difference between the actual grant proceeds we receive and the estimated grant proceeds the PSCW used to set electric retail rates for 2013 and 2014.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2), Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2)).

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

	Three Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Operating Revenues	$114.2	$1.6	$112.6
Operation and Maintenance Expense	4.2	0.1	4.3
Depreciation Expense	16.8	—	16.8
Operating Income	$93.2	$1.7	$91.5

Non-utility energy segment operating income increased by $1.7 million, or approximately 1.9%, when compared to the third quarter of 2012. The increase in operating revenues is primarily related to the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case.

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
AFUDC - Equity	$5.2	$(3.7)	$8.9
Other, net	(0.1)	(0.2)	0.1
Other Income, net	$5.1	$(3.9)	$9.0

Other income, net decreased by $3.9 million, or approximately 43.3%, when compared to the third quarter of 2012. The decrease in AFUDC - Equity is primarily related to units 7 and 8 of the Oak Creek AQCS project going into service in September 2012.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Gross Interest Costs	$64.6	$0.4	$65.0
Less: Capitalized Interest	2.6	(1.5)	4.1
Interest Expense, net	$62.0	$(1.1)	$60.9

Our gross interest costs decreased by $0.4 million, or approximately 0.6%, when compared to the third quarter of 2012. Our capitalized interest decreased by $1.5 million primarily because of lower construction work in progress. As a result, our net interest expense increased by $1.1 million, or 1.8%, as compared to the third quarter of 2012.

CONSOLIDATED INCOME TAX EXPENSE

For the third quarter of 2013, our effective tax rate applicable to continuing operations was 37.0% compared to 36.5% for the third quarter of 2012. This increase in our effective tax rate was due to reduced domestic production activities deductions and AFUDC - Equity. For additional information, see Note G -- Income Taxes in our 2012 Annual Report on Form 10-K.

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RESULTS OF OPERATIONS -- NINE MONTHS ENDED SEPTEMBER 30, 2013

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first nine months of 2013 with the first nine months of 2012, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Nine Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars, Except Per Share Amounts)		
Utility Energy Segment	$536.1	$2.9	$533.2
Non-Utility Energy Segment	276.4	6.2	270.2
Corporate and Other	(4.0)	0.5	(4.5)
Total Operating Income	808.5	9.6	798.9
Equity in Earnings of Transmission Affiliate	51.0	2.1	48.9
Other Income, net	15.3	(18.3)	33.6
Interest Expense, net	190.3	(9.0)	181.3
Income Before Income Taxes	684.5	(15.6)	700.1
Income Tax Expense	251.4	1.2	252.6
Net Income	$433.1	$(14.4)	$447.5
Diluted Earnings Per Share	$1.88	$(0.04)	$1.92

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $536.1 million of operating income during the first nine months of 2013, an increase of $2.9 million, or 0.5%, compared with the first nine months of 2012. The following table summarizes the operating income of this segment between the comparative periods:

	Nine Months Ended September 30		
Utility Energy Segment	2013	B (W)	2012
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,516.5	$65.4	$2,451.1
Gas	751.6	95.3	656.3
Other	28.6	3.8	24.8
Total Operating Revenues	3,296.7	164.5	3,132.2
Operating Expenses			
Fuel and Purchased Power	890.1	(37.3)	852.8
Cost of Gas Sold	446.9	(78.9)	368.0
Other Operation and Maintenance	1,097.7	(28.7)	1,069.0
Depreciation and Amortization	238.2	(19.4)	218.8
Property and Revenue Taxes	87.7	2.7	90.4
Total Operating Expenses	2,760.6	(161.6)	2,599.0
Operating Income	$536.1	$2.9	$533.2

Form 10-Q

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first nine months of 2013 with the first nine months of 2012:

	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2013	B (W)	2012	2013	B (W)	2012
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$913.1	$21.4	$891.7	6,103.6	(250.4)	6,354.0
Small Commercial/Industrial	798.0	18.9	779.1	6,700.1	(77.2)	6,777.3
Large Commercial/Industrial	566.4	(2.6)	569.0	6,885.6	(454.1)	7,339.7
Other - Retail	17.0	0.4	16.6	109.6	(1.6)	111.2
Total Retail	2,294.5	38.1	2,256.4	19,798.9	(783.3)	20,582.2
Wholesale - Other	109.3	(3.0)	112.3	1,444.7	331.6	1,113.1
Resale - Utilities	91.5	48.3	43.2	2,880.9	1,488.8	1,392.1
Other Operating Revenues	21.2	(18.0)	39.2	—	—	—
Total	$2,516.5	$65.4	$2,451.1	24,124.5	1,037.1	23,087.4
Weather -- Degree Days (a)						
Heating (4,316 Normal)				4,630	1,117	3,513
Cooling (720 Normal)				678	(363)	1,041

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

Our electric utility operating revenues increased by $65.4 million, or 2.7%, when compared to the first nine months of 2012. The most significant factors that caused a change in revenues were:

- Wisconsin net retail pricing increases of $87.9 million ($134.8 million less $46.9 million related to Section 1603 bill credits), which is primarily related to our 2013 Wisconsin Rate Case.
- A $48.3 million increase in sales for resale due to increased sales into the MISO Energy Markets as a result of increased availability of our generating units.
- A return to more normal weather as compared to the prior year that decreased electric revenues by an estimated $38.4 million.
- A $18.0 million decrease in other operating revenues, primarily driven by the amortization of $21.8 million in 2012 related to the settlement with the DOE.

As measured by cooling degree days, the first nine months of 2013 were 34.9% cooler than the same period in 2012 and 5.8% cooler than normal. Residential sales decreased by 3.9%, primarily because of weather. Sales to large commercial/industrial customers decreased by 6.2%, primarily because of a decrease in sales to the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 3.7%. Wholesale - Other sales increased by 29.8% primarily due to increased off-peak energy sales which generate lower incremental revenue because the majority of our wholesale revenue is tied to demand.

The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. See Factors Affecting Results, Liquidity and Capital Resources - Electric Transmission and Energy Markets - Restructuring in Michigan, for a discussion of the impact of industry restructuring in Michigan on our electric sales.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $37.3 million, or 4.4%, when compared to the first nine months of 2012. This increase was primarily caused by a 4.5% increase in total MWh sales.

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Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first nine months of 2013 with the first nine months of 2012. 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 $95.3 million, or 14.5%, and cost of gas sold increased by $78.9 million, or 21.4%, due to cooler weather and an increase in the commodity cost of natural gas.

	Nine Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Gas Operating Revenues	$751.6	$95.3	$656.3
Cost of Gas Sold	446.9	(78.9)	368.0
Gross Margin	$304.7	$16.4	$288.3

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first nine months of 2013 with the first nine months of 2012:

	Nine Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2013	B (W)	2012	2013	B (W)	2012
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$196.0	$11.5	$184.5	567.8	130.9	436.9
Commercial/Industrial	65.5	6.1	59.4	332.2	78.0	254.2
Interruptible	1.3	0.1	1.2	12.9	3.0	9.9
Total Retail	262.8	17.7	245.1	912.9	211.9	701.0
Transported Gas	37.4	(1.2)	38.6	777.7	(99.2)	876.9
Other	4.5	(0.1)	4.6	—	—	—
Total	$304.7	$16.4	$288.3	1,690.6	112.7	1,577.9
Weather -- Degree Days (a)						
Heating (4,316 Normal)				4,630	1,117	3,513

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

Our gas margin increased by $16.4 million, or approximately 5.7%, when compared to the first nine months of 2012. This increase primarily relates to an increase in sales volumes as a result of cooler weather during the first nine months of 2013 that increased heating loads. We estimate that weather increased gas margins by approximately $40.4 million. As measured by heating degree days, the first nine months of 2013 were 31.8% cooler than the same period in 2012 and 7.3% cooler than normal. Gas margins were reduced by approximately $28.4 million because of lower gas rates that became effective January 1, 2013.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by $28.7 million, or approximately 2.7%, when compared to the first nine months of 2012. This increase was primarily driven by the reinstatement of $111.0 million of regulatory amortizations, offset in part by a $35.1 million reduction in bad debt expense related to our natural gas customers and continued cost control efforts across the utility.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $19.4 million, or approximately 8.9%, when compared to the first nine months of 2012 primarily because of an overall increase in utility plant in service. The emission control equipment for units 5 and 6 of the Oak Creek AQCS project went into service in March 2012, and for units 7 and 8 in September 2012.

Section 1603 Renewable Energy Treasury Grant

For a discussion of the impact of the Section 1603 renewable energy treasury grant on our results of operations, see Results of Operations -- Three Months Ended September 30, 2013 -- Section 1603 Renewable Energy Treasury Grant.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

This segment reflects the lease revenues associated with PWGS 1, PWGS 2, OC 1 and OC 2, as well as the depreciation expense. The operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Nine Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Operating Revenues	$337.3	$5.1	$332.2
Operation and Maintenance Expense	10.6	1.1	11.7
Depreciation Expense	50.3	—	50.3
Operating Income	$276.4	$6.2	$270.2

Non-utility energy segment operating income increased by $6.2 million, or approximately 2.3%, when compared to the first nine months of 2012. The increase in operating revenues is primarily related to the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case.

CONSOLIDATED OTHER INCOME, NET

	Nine Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
AFUDC - Equity	$14.1	$(17.6)	$31.7
Other, net	1.2	(0.7)	1.9
Other Income, net	$15.3	$(18.3)	$33.6

Other income, net decreased by $18.3 million, or approximately 54.5%, when compared to the first nine months of 2012. The decrease in AFUDC - Equity is primarily related to the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8.

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CONSOLIDATED INTEREST EXPENSE, NET

	Nine Months Ended September 30		
	2013	B (W)	2012
	(Millions of Dollars)		
Gross Interest Costs	$197.4	$(2.0)	$195.4
Less: Capitalized Interest	7.1	(7.0)	14.1
Interest Expense, net	$190.3	$(9.0)	$181.3

Our gross interest costs increased by $2.0 million, or approximately 1.0%, when compared to the first nine months of 2012. Our capitalized interest decreased by $7.0 million primarily because of lower construction work in progress. As a result, our net interest expense increased by $9.0 million, or 5.0%, as compared to the first nine months of 2012.

CONSOLIDATED INCOME TAX EXPENSE

For the first nine months of 2013, our effective tax rate applicable to continuing operations was 36.7% compared to 36.1% for the first nine months of 2012. This increase in our effective tax rate was due to reduced domestic production activities deductions and AFUDC - Equity. For additional information, see Note G -- Income Taxes in our 2012 Annual Report on Form 10-K. We expect our 2013 annual effective tax rate to be between 36% and 37%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

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

	2013	2012
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$1,050.3	$992.4
Investing Activities	$(544.8)	$(491.4)
Financing Activities	$(522.6)	$(502.1)

Operating Activities

Cash provided by operating activities increased by $57.9 million during the first nine months of 2013 as compared to the same period in 2012. The increase is primarily because of lower contributions to our benefit plans. During the first nine months of 2013, we made no contributions to our benefit plans, compared to contributions of $100 million during the first nine months of 2012. In addition, we had higher depreciation expense and higher amortization expense. Included in the higher amortization expense is a $64.7 million increase in the amortization of regulatory items. Partially offsetting these items are lower net income and higher working capital requirements.

Investing Activities

Cash used in investing activities increased by $53.4 million during the first nine months of 2013 as compared to the same period in 2012. Our change in restricted cash decreased by $33.3 million which is related to the 2012 release of restricted cash through bill credits and reimbursements of costs associated with the DOE settlement. Our capital expenditures increased by $20.2 million during the first nine months of 2013 as compared to the same period in 2012, primarily because of the increase in spending on upgrades to our utility infrastructure.

Financing Activities

Cash used in financing activities increased by $20.5 million during the first nine months of 2013 as compared to the same period in 2012. During the first nine months of 2013, we retired $345.9 million more of long-term debt as compared to the same period in 2012. In addition, Wisconsin Electric issued $250 million of long-term debt in June 2013. The net proceeds of the debt issuance were used to repay short-term debt and for other corporate purposes. During the first nine months of 2013, we repurchased $103.0 million of common stock under our May 2011 share repurchase program and another $84.9 million of common stock to fulfill exercised stock options and restricted stock awards, compared to $14.0 million and $91.0 million, respectively, during the same period in 2012. Our dividends paid on common stock increased by $34.9 million in the first nine months of 2013 as compared to the same period last year, as a result of increases in the quarterly common stock dividend of 13.3% and 12.5% in the first quarter and third quarter, respectively. These factors were partially offset by a decrease in the amount of short-term debt we repaid in 2013. During the first nine months, repayment of short-term debt was $183.9 million lower in 2013 as compared to the same period in 2012.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of September 30, 2013, our current liabilities exceeded our current assets by approximately $53.0 million. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place for on-going operations. We also have access to the capital markets to finance our construction program and to refinance current maturities of long-term debt if necessary.

Liquidity

We anticipate meeting our capital requirements during the remainder of 2013 and beyond 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.

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

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

As of September 30, 2013, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $361.8 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first nine months of 2013, our maximum commercial paper outstanding was $594.5 million with a weighted-average interest rate of 0.26%.

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, 2013:

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

Wisconsin Energy	$400.0	$0.1	$399.9	December 2017
Wisconsin Electric	$500.0	$6.1	$493.9	December 2017
Wisconsin Gas	$350.0	$—	$350.0	December 2017

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The following table shows our capitalization structure as of September 30, 2013, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated notes due 2067 (Junior Notes):

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$4,198.1	$4,448.1
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,741.9	4,491.9
Short-Term Debt	361.8	361.8
Total Capitalization	$9,332.2	$9,332.2
Total Debt	$5,103.7	$4,853.7
Ratio of Debt to Total Capitalization	54.7 %	52.0 %

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of September 30, 2013 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of September 30, 2013, the repurchased bonds were still outstanding, but were not reported as long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Bonus Depreciation Provisions

The American Taxpayer Relief Act of 2012 was signed into law on January 2, 2013, which extended the 50% bonus depreciation rules to include assets placed in service in 2013. These rules will apply to the biomass plant we are constructing in Rothschild, which is expected to be completed during the fourth quarter of 2013. As a result of the increased federal tax depreciation for 2013 and prior years, we do not anticipate making federal income tax payments for 2013.

Credit Rating Risk

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

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

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See Capital Resources and Requirements -- Credit Rating Risk in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2012 Annual Report on Form 10-K for additional information related to our credit rating risk.

Capital Requirements

Capital Expenditures: Capital requirements during the remainder of 2013 are expected to be principally for capital expenditures in our utility operations relating to our electric and gas distribution systems and our biomass facility. We estimate that we will spend approximately $690 million on consolidated capital expenditures during 2013.

Common Stock Matters: On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. We expect funds for the repurchases will continue to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through September 30, 2013, we have acquired approximately 7.1 million shares in the open market at a cost of $254.8 million pursuant to this program. For additional information regarding the share repurchases, see Part II, Item 2 - Unregistered Sales of Equity Securities and Use of Proceeds in this report.

On July 18, 2013, the Board of Directors decided to accelerate the dividend action that was planned for the first quarter of 2014. As a result, the board declared a quarterly cash dividend of $0.3825 per share on our common stock. This represents an increase of $0.0425 per share in the quarterly dividend, and raises the annual dividend rate from $1.36 per share to $1.53 per share. The Board of Directors also affirmed our dividend policy that targets a payout ratio that trends to 65-70% in 2017.

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 -- Variable Interest Entities in the Notes to Consolidated Condensed Financial Statements in this report.

Contractual Obligations/Commercial Commitments: Our total contractual obligations and other commercial commitments were approximately $22.4 billion as of September 30, 2013 compared with $23.1 billion as of December 31, 2012.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

The following is a discussion of certain factors that may affect our results of operations, liquidity and capital resources. The following discussion should be read together with the information under the heading "Factors Affecting Results, Liquidity and Capital Resources" in Item 7 of our 2012 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

All of the PTF units are in service and are positioned to provide a significant portion of our future generation needs. We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2, OC 1 and OC 2 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC.

As part of our 2013 Wisconsin Rate Case, the PSCW determined that 100% of the construction costs for our Oak Creek expansion units were prudently incurred, and approved the recovery in rates of more than 99.5% of these costs. In addition, the PSCW deferred the final decision regarding $24 million related to the Oak Creek expansion fuel flexibility project until a future rate proceeding. See Other Matters below for additional information about the fuel flexibility project.

We Power assigned its warranty rights to Wisconsin Electric upon turnover of each of the Oak Creek expansion units. The warranty claim for costs incurred to repair steam turbine corrosion damage identified on both units was scheduled to go to arbitration in October 2013, but we entered into a settlement agreement with Bechtel Power Corporation (Bechtel) on June 21, 2013 resolving the claim, as well as several other warranty claims. This settlement did not have a material impact to our financial statements. Bechtel and Wisconsin Electric continue to work through two remaining items.

Pursuant to the terms of this settlement agreement, Bechtel achieved final acceptance of both Oak Creek expansion units. In turn, we paid $5.0 million to Bechtel, which represents the amount agreed to as part of the December 2009 settlement and release agreement for achieving final acceptance.

See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2012 Annual Report on Form 10-K for additional information on PTF.

UTILITY RATES AND REGULATORY MATTERS

2013 Wisconsin Rate Case: On March 23, 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. On December 20, 2012, the PSCW approved the following rate adjustments:

- A net bill increase related to non-fuel costs for Wisconsin Electric's Wisconsin retail electric customers of approximately $70 million (2.6%) for 2013. This amount reflects an offset of approximately $63 million (2.3%) related to the proceeds of the Section 1603 renewable energy cash grant Wisconsin Electric expects to receive upon completion of its biomass facility currently under construction. Absent this offset, the retail electric rate increase for non-fuel costs is approximately $133 million (4.8%) for 2013.
- Absent an adjustment for any remaining energy cash credits, an electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014.
- Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013.
- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Electric rates reflect a $6.4 million reduction in bad debt expense.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Gas rates reflect a $43.8 million reduction in bad debt expense.
- An increase of approximately $1.3 million (6.0%) for Wisconsin Electric's Downtown Milwaukee (Valley) steam utility customers for 2013 and another $1.3 million (6.0%) in 2014.
- An increase of approximately $1 million (7.0%) in 2013 and $1 million (6.0%) in 2014 for Wisconsin Electric's Milwaukee County steam utility customers.

These rate adjustments were effective January 1, 2013. In addition, the PSCW indicated that Wisconsin Electric's and Wisconsin Gas' allowed return on equity would remain at 10.4% and 10.5%, respectively. The PSCW also approved escrow accounting treatment for the energy cash grant.

2014 Fuel Recovery Request: On July 30, 2013, Wisconsin Electric filed its 2014 fuel plan with the PSCW requesting authority to refund Wisconsin retail electric customers approximately $30 million in the form of a fuel credit related to a reduction in delivered coal costs. We anticipate an order from the PSCW by the end of the year.

2012 Fuel Recovery Request: In August 2011, Wisconsin Electric filed a $50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase were projected higher coal, coal transportation and purchased power costs. In January 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE regarding the storage of spent nuclear fuel, resulting in no change in customer bills. In March of this year, Wisconsin Electric filed their annual fuel reconciliation for the 2012 fuel recovery request. The reconciliation was approved by the PSCW and we received the written order on July 31, 2013.

Renewable Energy Portfolio: We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced in June 2011. We currently expect to invest $269.5 million, excluding AFUDC, in the plant. We are targeting completion of the facility by the end of 2013.

Oak Creek Air Quality Control System: In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008. In March 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. In September 2012, the equipment for units 7 and 8 was placed into commercial operation. The final cost of completing this project was approximately $740 million ($900 million including AFUDC). The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree we entered into with the United States Environmental Protection Agency (EPA) in 2003.

Western Gas Lateral: We are projecting the need for additional capacity for our natural gas distribution network in the western part of Wisconsin to address reliability and meet customer demand. We filed an application with the PSCW seeking approval to construct a new natural gas lateral on March 28, 2013. The anticipated cost of the initial phase of this project is approximately $150 million to $170 million, excluding AFUDC.

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2012 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

ELECTRIC TRANSMISSION AND ENERGY MARKETS

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the Locational Marginal Price (LMP) system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through Auction Revenue Rights (ARRs) and FTRs. ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2013 through May 31, 2014. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

Restructuring in Michigan: Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Sales to these customers, including the mines, totaled 2,173.6 GWh, or 7.6% of our retail electric sales for the year ended December 31, 2012. We do not expect the loss of the mines or the other customers to have a material impact on our consolidated results of operations in 2013. Previously, the owner of the mines announced that they would shut down the Empire mine by the end of 2014 or beginning of 2015.

Before implementation of steps to mitigate the loss of these sales, we estimate that the impact of these losses in 2014 would be approximately $50 million to $54 million before income taxes. We have taken, and will continue to take, multiple steps to mitigate these losses for 2014 and going forward.

We filed a request with MISO to suspend the operation of all five units at Presque Isle Power Plant (PIPP). On October 16, 2013, MISO informed us that the operation of all units is necessary to maintain reliability in the Upper Peninsula of Michigan. As a result, we are eligible for system support resource (SSR) payments from MISO to recover costs for operating the units, and we will be working with MISO to determine the amount of the SSR payments. We expect to become eligible to receive SSR payments in February of 2014. Depending on the level of operating and maintenance expenses included in these payments and the degree to which costs for new capital investments and carrying costs for previous capital investments are reflected, these payments could range from $35 million to $82 million on an annualized basis.

Wisconsin Electric filed an application with the MPSC requesting authority to defer all fixed production costs that would have been recovered from the customers who switched to an alternative electric supplier. In August 2013, the MPSC issued an order approving the deferral of costs allocable to our remaining Michigan retail customers. On September 30, 2013, we filed a petition for re-hearing with the MPSC requesting reconsideration of its deferral order. Our ability to collect the deferred costs will be determined in a subsequent rate proceeding.

Wisconsin Electric files bi-annual retail rate cases in Wisconsin. Our next electric rate case in Wisconsin is for rates to be implemented in January 2015. Wholesale electric rates are set under FERC formula cost-based rates and are adjusted annually. We believe that prudently incurred utility costs will be recovered in future Wisconsin retail rate cases and FERC filings.

Although the financial impact in future periods is uncertain, we expect that our net financial exposure will be immaterial if the mitigation efforts outlined above are successful.

ENVIRONMENTAL MATTERS

Air Quality

Sulfur Dioxide Standard: In June 2010, the EPA issued a new 1 hour Sulfur Dioxide (SO_2) National Ambient Air Quality Standard that became effective in August 2010. This standard represented a significant change from the previous SO_2 standard. The implementation guidance for the new standard, among other things, required attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data. The EPA has since advised that, based on stakeholder input, it is revisiting this implementation guidance. The EPA has issued two technical assistance documents for comment in 2013, and expects to issue a rule in 2014 that will establish requirements for characterizing SO_2 air quality in priority areas.

Various parties have submitted judicial and administrative challenges to this rule, and litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging, among other things, the stringency of the standards and the EPA's plans to require attainment designations to be based on modeling.

If the new standard remains in place, we do not believe that we will need to make any significant additional expenditure at the majority of our generating units because of prior investments in pollution control equipment. However, if the new standard does remain in place we believe that additional environmental controls will be required at PIPP located in the Upper Peninsula of Michigan. In November of 2012 we entered into a joint venture agreement with Wolverine Power Supply Cooperative, Inc. (Wolverine) whereby Wolverine would pay for the installation of the air quality control systems at PIPP and receive a minority undivided ownership interest in the plant in return. However, in light of the recent loss of retail electric customers in Michigan due to that state’s alternative electric supplier program (see Restructuring in Michigan under Electric Transmission and Energy Markets) we are re-evaluating options related to the ownership and operation of PIPP including different alternatives for the joint venture with Wolverine. At the same time, we are analyzing several environmental compliance options at PIPP.

The new standard may also require us to make modifications at some of our smaller generation units.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final Mercury and Air Toxics Standard (MATS) rule, which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. We currently anticipate that only PIPP will require modifications, and are currently evaluating several available options for PIPP to comply with MATS. If the joint venture with Wolverine moves forward we expect the modifications to be funded by Wolverine. In April 2013, we received a one year MATS compliance extension through April 16, 2016 from the Michigan Department of Environmental Quality (MDEQ).

Cross-State Air Pollution Rule: In August 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of Nitrogen Oxide (NO_X) and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation plan. Even with technical revisions to the rule by the EPA, PIPP may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR, keeping the CAIR in effect. The EPA petitioned the United States Supreme Court, who agreed to hear the case. A decision is expected in mid-2014.

Climate Change: Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The President and his administration recently reaffirmed that regulation of greenhouse gas emissions continues to be a top priority. In June 2013, the President issued a presidential memorandum instructing the EPA to, among other things, issue rules pertaining to greenhouse gas emissions from both new and existing power plants.

The EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the Clean Air Act. On September 20, 2013, the EPA withdrew its 2012 proposed New Source Performance Standards greenhouse gas emissions rule, and issued new proposed rules with greenhouse gas limits for new fossil fueled power plants. The rule does not apply to certain natural gas fueled peaking plants, biomass units or oil fueled stationary combustion turbines.

With respect to existing generating units, the EPA has indicated that it intends to issue a proposed rule in June 2014, a final rule by June 2015 and require State Implementation Plans to be submitted by June 30, 2016. Any such regulations may impact how we operate our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition. For additional information, see the caption "We may face significant costs to comply with the regulation of greenhouse gas emissions." under Item 1A Risk Factors in our 2012 Annual Report on Form 10-K.

Valley Power Plant Conversion: In August 2012, we announced plans to convert the fuel source for Valley Power Plant (VAPP) from coal to natural gas. We currently expect the cost of this conversion to be between $65 million and $70 million excluding AFUDC, and, subject to receipt of PSCW approval and a construction air permit from the WDNR, anticipate that the conversion will be completed by the end of 2015 or early 2016. We filed for a Certificate of Authority from the PSCW on April 26, 2013. The construction air permit for the gas conversion is expected to be issued by the WDNR before the end of the year.

In June 2012, we received approval from the PSCW to replace and upgrade the Lincoln Arthur natural gas main, which has the capability to accommodate the increased natural gas required for the conversion of VAPP to natural gas. Construction began on the Lincoln Arthur natural gas main in March 2013.

Water Quality

Steam Electric Effluent Guidelines: These guidelines regulate waste water discharges from our power plant processes. In June 2013, the EPA issued a proposed rule for comment to modify these guidelines. We submitted comments primarily addressing potential effects to our wastewater treatment facilities and coal combustion residuals effluent management activities. The rules are expected to be finalized by May 2014. After promulgation of the final rules, the WDNR and MDEQ will need to modify state rules accordingly and then incorporate new requirements into our facility permits. The rule compliance deadline is as soon as possible after July 1, 2017 with full compliance expected by July 1, 2022. We already meet many of the proposed requirements defined by EPA, and as a result believe we will be well positioned to comply with the proposed guidelines. There are several available options outlined in the proposed rule. The amount of additional costs we may need to incur to comply with the new guidelines, if any, will depend on which option(s) the EPA selects to incorporate into the final guidelines. Until the rules are finalized, we are unable to determine the impact on our facilities.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2012 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. In May 2013, we began testing various combinations of sub-bituminous coal and bituminous coal to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make any fuel flexibility modifications. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed a petition for a contested case hearing with the WDNR to challenge the issuance of the air construction permit. The WDNR has granted that petition, but a hearing has not yet been scheduled.

Paris Generating Station Units 1 and 4 Temporary Outage: Between 2000 and 2002, we replaced the blades on the four Paris Generating Station (PSGS) combustion turbine generators with blades that were approximately 7% more efficient. Although the work was performed as routine maintenance that we did not believe required a construction permit at the time and the plant has not been operated to use the potential additional capacity, the WDNR has indicated that it now considers this maintenance to be a modification requiring a construction permit. The WDNR issued a Notice of Violation (NOV) to Wisconsin Electric on January 7, 2013 alleging violations of the new source review rules and certain Wisconsin environmental rules. At the same time, the WDNR also issued an administrative order that prohibits us from operating PSGS Units 1 and 4 until the earlier of: (1) Units 1 and 4 achieve the applicable NO_x emission rates; (2) the Wisconsin regulations are revised so that Units 1 and 4 can achieve the emission limits or are no longer subject to the limits; (3) the alleged modification is resolved through a consent decree; or (4) until a court decides that the blade replacement project was not a major modification. We are presently evaluating alternative approaches to return these peaking units to service, and expect that Units 1 and 4 will remain out of service until at least 2014. In addition, we may be subject to fines and penalties. In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order. The WDNR has granted that petition, but a hearing has not yet been scheduled. In addition, in May 2013, the WDNR referred the matter to the Wisconsin Department of Justice (DOJ) for alleged violations of air management statutes and rules.

We evaluated the impact that this outage may have on network reliability, and concluded that we will not need to find alternative sources of generation in the short-term to replace the generation from these units during the temporary outage.

PSGS Units 2 and 3 remain available for operation because the turbine blade maintenance on these units occurred prior to a rule change in 2001.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2012. 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 2012 Annual Report on Form 10-K, as well as Note 5 -- Fair Value Measurements and Note 6 -- Derivative Instruments in the Notes to Consolidated Condensed Financial Statements in this report.

ITEM 4. CONTROLS AND PROCEDURES

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

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

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2012 Annual Report on Form 10-K.

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

ENVIRONMENTAL MATTERS

Paris Generating Station: See Factors Affecting Results, Liquidity and Capital Resources -- Other Matters for information concerning a NOV issued in connection with the replacement of certain turbine blades as part of maintenance performed on Units 1 and 4 at PSGS.

Bluff Collapse: On October 31, 2011, a portion of the bluff at our Oak Creek Power Plant collapsed. The affected area, located south of the new AQCS, was a former ravine that had been filled with coal ash prior to the advent of landfill regulations. Following the receipt of permits and approvals from the WDNR, bluff reconstruction and stabilization were completed in November 2012. We received final spill closure related to our rework of the storm water management infrastructure from the WDNR in December 2012, following submission of environmental studies and reports. In addition, the EPA issued its final incident situation report in November 2012. The final construction documentation report was submitted to the WDNR in December 2012.

A June 2012 letter from the WDNR alleged non-compliance with certain environmental regulations. In July 2012, the WDNR referred the matter to the DOJ. On July 8, 2013, the Racine County Circuit Court approved a stipulation and settlement agreement in State of Wisconsin v. Wisconsin Electric Power Company (Racine County Case Number 2013CX000002). As part of the settlement agreement, Wisconsin Electric paid a total of $100,000 to reimburse the state of Wisconsin for its costs in responding to the collapse and for its attorneys' fees, as well as for assessments and penalties. This settlement agreement fully resolves this matter.

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

UTILITY RATES AND REGULATORY MATTERS

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

ITEM 1A. RISK FACTORS

Other than as set forth below, there have been no material changes from the risk factors presented in our Annual Report on Form 10-K for the year ended December 31, 2012. See Item 1A. Risk Factors in our 2012 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

Restructuring in the regulated energy industry could have a negative impact on our business.

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us. It is uncertain whether retail access might be implemented in Wisconsin.

Michigan has adopted retail choice. Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Sales to these customers, including the mines, totaled 2,173.6 GWh, or 7.6% of our retail electric sales for the year ended December 31, 2012. Previously, the owner of the mines announced that they would shut down the Empire mine by the end of 2014 or beginning of 2015. Before implementation of steps to mitigate the loss of these sales, we estimate that the impact of these losses in 2014 would be approximately $50 million to $54 million before income taxes.

FERC continues to support the existing Regional Transmission Organizations (RTO) that affect the structure of the wholesale market within these RTOs. In connection with its status as a FERC approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. The MISO Energy Markets rules require that all market participants submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes a LMP that reflects the market price for energy. As a participant in the MISO Energy Markets, we are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining stability of the transmission system. MISO also implemented an Ancillary Services Market for operating reserves that was simultaneously co-optimized with its existing energy markets.

These market designs have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the market and the costs associated with estimated payment settlements.

Form 10-Q

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

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three months ended September 30, 2013:

ISSUER PURCHASES OF EQUITY SECURITIES

2013	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (a)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
July 1 - July 31	920,036	$42.14	920,036	$54.8
August 1 - August 31	201,667	$41.80	201,667	$46.3
September 1 - September 30	24,893	$40.15	24,893	$45.3
Total	1,146,596	$42.04	1,146,596	

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

ITEM 6. EXHIBITS

Exhibit No.

10	Material Contracts
10.1	First Amendment to Restated Rabbi Trust Agreement (the Non-Qualified Trust Agreement) by and between Wisconsin Energy Corporation and The Northern Trust Company, effective as of July 23, 2013.
31	Rule 13a-14(a) / 15d-14(a) Certifications
31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certifications
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	

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

101 Interactive Data File

Form 10-Q

SIGNATURES

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

	WISCONSIN ENERGY CORPORATION (Registrant)
Date: November 1, 2013	/s/STEPHEN P. DICKSON Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer