OTTER TAIL CORP
Form 10-Q
May 11, 2009

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2009

OR

o **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 0-368

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota	41-0462685
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
215 South Cascade Street, Box 496, Fergus Falls, Minnesota	56538-0496
(Address of principal executive offices)	(Zip Code)

866-410-8780

(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 þ NO o

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 o No o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).
YES o NO þ

Indicate the number of shares outstanding of each of the issuer s classes of Common Stock, as of the latest practicable date:

April 30, 2009 35,466,387 Common Shares ($5 par value)

OTTER TAIL CORPORATION
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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)
-Assets-

	March 31, 2009	December 31, 2008
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 3,112	$ 7,565
Accounts Receivable:		
Trade Net	122,576	136,609
Other	9,077	13,587
Inventories	97,690	101,955
Deferred Income Taxes	8,386	8,386
Accrued Utility and Cost-of-Energy Revenues	16,902	24,030
Costs and Estimated Earnings in Excess of Billings	55,308	65,606
Income Taxes Receivable	32,786	26,754
Other	18,832	8,519
Total Current Assets	364,669	393,011
Investments	9,511	7,542
Other Assets	23,395	22,615
Goodwill	106,778	106,778
Other Intangibles Net	35,002	35,441
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,988	7,247
Regulatory Assets and Other Deferred Debits	80,417	82,384
Total Deferred Debits	87,405	89,631
Plant		
Electric Plant in Service	1,206,365	1,205,647
Nonelectric Operations	338,284	321,032
Total Plant	1,544,649	1,526,679
Less Accumulated Depreciation and Amortization	562,266	548,070
Plant Net of Accumulated Depreciation and Amortization	982,383	978,609
Construction Work in Progress	61,800	58,960
Net Plant	1,044,183	1,037,569

Total	$ 1,670,943	$ 1,692,587

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Balance Sheets
(not audited)
-Liabilities-

	March 31, 2009	December 31, 2008
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 149,063	$ 134,914
Current Maturities of Long-Term Debt	3,687	3,747
Accounts Payable	92,665	113,422
Accrued Salaries and Wages	17,035	29,688
Accrued Taxes	9,043	10,939
Other Accrued Liabilities	12,190	12,034
Total Current Liabilities	283,683	304,744
Pensions Benefit Liability	81,868	80,912
Other Postretirement Benefits Liability	33,083	32,621
Other Noncurrent Liabilities	19,768	19,391
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	128,371	123,086
Deferred Tax Credits	33,750	34,288
Regulatory Liabilities	64,962	64,684
Other	439	397
Total Deferred Credits	227,522	222,455
Capitalization		
Long-Term Debt, Net of Current Maturities	338,797	339,726
Class B Stock Options of Subsidiary	1,220	1,220
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2009 and 2008 155,000 Shares	15,500	15,500
Cumulative Preference Shares Authorized 1,000,000 Shares without Par Value; Outstanding None		
Common Shares, Par Value $5 Per Share Authorized 50,000,000 Shares; Outstanding 2009 35,409,133 and 2008 35,384,620	177,046	176,923
Premium on Common Shares	241,886	241,731
Retained Earnings	254,034	260,364

Accumulated Other Comprehensive Loss	(3,464)	(3,000)
Total Common Equity	669,502	676,018
Total Capitalization	1,025,019	1,032,464
Total	$ 1,670,943	$ 1,692,587

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended March 31, 2009	2008
	(In thousands, except share and per share amounts)	
Operating Revenues		
Electric	$ 88,479	$ 97,505
Nonelectric	188,760	202,732
Total Operating Revenues	277,239	300,237
Operating Expenses		
Production Fuel Electric	18,659	19,904
Purchased Power Electric System Use	17,373	18,986
Electric Operation and Maintenance Expenses	26,930	26,743
Cost of Goods Sold Nonelectric (depreciation included below)	152,961	165,223
Other Nonelectric Expenses	30,634	34,747
Product Recall and Testing Costs	1,766	
Depreciation and Amortization	17,817	14,913
Property Taxes Electric	2,490	2,624
Total Operating Expenses	268,630	283,140
Operating Income	8,609	17,097
Other Income	667	962
Interest Charges	6,270	6,711
Income Before Income Taxes	3,006	11,348
Income Taxes	(1,382)	3,118
Net Income	4,388	8,230
Preferred Dividend Requirements	184	184
Earnings Available for Common Shares	$ 4,204	$ 8,046
Earnings Per Common Share:		
Basic	$ 0.12	$ 0.27
Diluted	$ 0.12	$ 0.27
Average Number of Common Shares Outstanding:		
Basic	35,324,736	29,818,079
Diluted	35,488,640	30,061,865

Dividends Per Common Share	$	0.2975	$	0.2975

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Cash Flows
(not audited)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 4,388	$ 8,230
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	17,817	14,913
Deferred Tax Credits	(538)	(385)
Deferred Income Taxes	5,487	3,722
Change in Deferred Debits and Other Assets	569	701
Change in Noncurrent Liabilities and Deferred Credits	1,916	(1,147)
Allowance for Equity (Other) Funds Used During Construction	(91)	348
Change in Derivatives Net of Regulatory Deferral	(809)	(1,511)
Stock Compensation Expense	837	699
Other Net	195	252
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	18,482	8,364
Change in Inventories	4,072	(18,230)
Change in Other Current Assets	9,864	(3,529)
Change in Payables and Other Current Liabilities	(33,430)	(5,506)
Change in Interest and Income Taxes Payable/Receivable	(6,878)	433
Net Cash Provided by Operating Activities	21,881	7,354
Cash Flows from Investing Activities		
Capital Expenditures	(26,756)	(57,656)
Proceeds from Disposal of Noncurrent Assets	840	464
Net (Increase) Decrease in Other Investments	(2,834)	530
Net Cash Used in Investing Activities	(28,750)	(56,662)
Cash Flows from Financing Activities		
Net Short-Term Borrowings	14,149	27,200
Proceeds from Issuance of Common Stock	7	454
Common Stock Issuance Expenses	(17)	
Payments for Retirement of Common Stock	(160)	(2)
Proceeds from Issuance of Long-Term Debt	1	1,135
Short-Term and Long-Term Debt Issuance Expenses	(71)	(19)
Payments for Retirement of Long-Term Debt	(982)	(984)
Dividends Paid	(10,718)	(9,077)
Net Cash Provided by Financing Activities	2,209	18,707
Effect of Foreign Exchange Rate Fluctuations on Cash	207	224

Net Change in Cash and Cash Equivalents	(4,453)	(30,377)
Cash and Cash Equivalents at Beginning of Period	7,565	39,824
Cash and Cash Equivalents at End of Period	$ 3,112	$ 9,447

See accompanying notes to consolidated financial statements

OTTER TAIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated results of operations for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2008, 2007 and 2006 included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008. Because of seasonal and other factors, the earnings for the three months ended March 31, 2009 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following notes are numbered to correspond to numbers of the notes included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

1. Summary of Significant Accounting Policies

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as the electric utility s forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company s operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company s consolidated revenues recorded under the percentage-of-completion method were 29.2% for the three months ended March 31, 2009 and 28.2% for the three months ended March 31, 2008. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company s wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at any point in time during a contract, a projected loss for the entire contract is estimated and recognized.

The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	March 31, 2009	December 31, 2008
Costs Incurred on Uncompleted Contracts	$ 490,413	$ 377,237
Less Billings to Date	(503,159)	(366,931)
Plus Estimated Earnings Recognized	62,406	47,355
	$ 49,660	$ 57,661

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The following amounts are included in the Company s consolidated balance sheets. Billings in excess of costs and estimated earnings on uncompleted contracts are included in Accounts Payable:

(in thousands)	March 31, 2009	December 31, 2008
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$55,308	$65,606
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(5,648)	(7,945)
	$49,660	$57,661

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $48,328,000 as of March 31, 2009 and $59,300,000 as of December 31, 2008. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Retainage

Accounts Receivable include amounts billed by the Company s subsidiaries under contracts that have been retained by customers pending project completion of $9,353,000 on March 31, 2009 and $10,311,000 on December 31, 2008.

Sales of Receivables

In March 2008, DMI entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $38.8 million have been sold in 2009. Discounts and commissions and fees of $175,000 for the three months ended March 31, 2009 were charged to operating expenses in the consolidated statements of income. In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Marketing and Sales Incentive Costs

ShoreMaster, Inc. (ShoreMaster), the Company s waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with Emerging Issues Task Force Issue No. 01-9, *Accounting for Consideration Given by a Vendor to a Customer (Including a Reseller of a Vendor s Products)*. The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs of $145,000 for the three months ended March 31, 2009 were charged to revenue. No financing assistance costs were charged to revenue in the three months ended March 31, 2008.

Supplemental Disclosures of Cash Flow Information

(in thousands)	Three Months Ended March 31, 2009	2008
Decreases in Accounts Payable and Other Liabilities Related to Capital Expenditures	$(2,191)	$(20,554)

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Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, *Fair Value Measurements*, for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company s assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2009:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market, Mutual Funds and Cash	$1,213	$	$	$ 1,213
Cash Surrender Value of Life Insurance Policies		8,112		8,112
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,450		10,450
Forward Energy Contracts		3,159		3,159
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,503			3,503
U.S. Government Debt Securities	3,201			3,201
Total Assets	$7,917	$21,721	$	$29,638
Liabilities:				
Forward Energy Contracts	$	$ 2,569	$	$ 2,569
Forward Foreign Currency Exchange Contracts	295			295
Asset Retirement Obligations			3,367	3,367
Total Liabilities	$ 295	$ 2,569	$ 3,367	$ 6,231
Net Assets (Liabilities)	$7,622	$19,152	$(3,367)	$23,407

Inventories

Inventories consist of the following:

	March 31,	December 31,

(in thousands)	2009	2008
Finished Goods	$34,138	$ 38,943
Work in Process	8,397	10,205
Raw Material, Fuel and Supplies	55,155	52,807
Total Inventories	$97,690	$101,955

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Other Intangible Assets

The following table summarizes the components of the Company s intangible assets at March 31, 2009 and December 31, 2008:

March 31, 2009 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,190	$ 1,883	$ 307	3 - 5 years
Customer Relationships	26,832	2,738	24,094	15 - 25 Years
Other Intangible Assets Including Contracts	2,359	1,620	739	5 - 30 Years
Total	$ 31,381	$ 6,241	$ 25,140	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,862	$	$ 9,862	

December 31, 2008 *(in thousands)*				
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,250	$ 1,889	$ 361	3 - 5 Years
Customer Relationships	26,854	2,429	24,425	15 - 25 Years
Other Intangible Assets Including Contracts	2,710	1,921	789	5 - 30 Years
Total	$ 31,814	$ 6,239	$ 25,575	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,866	$	$ 9,866	

The amortization expense for these intangible assets was $417,000 for the three months ended March 31, 2009 compared to $211,000 for the three months ended March 31, 2008. The estimated annual amortization expense for these intangible assets for the next five years is $1,633,000 for 2009, $1,461,000 for 2010, $1,332,000 for 2011, $1,312,000 for 2012 and $1,308,000 for 2013.

Comprehensive Income

(in thousands)	Three Months Ended March 31, 2009	2008
Net Income	$4,388	$8,230
Other Comprehensive Loss (net-of-tax):		
Foreign Currency Translation Loss	(424)	(452)
	15	43

Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs		
Unrealized (Loss) Gain on Available-for-Sale Securities	(55)	59
Total Other Comprehensive Loss	(464)	(350)
Total Comprehensive Income	$3,924	$7,880

New Accounting Standards

SFAS No. 141 (revised 2007), ***Business Combinations (SFAS No. 141(R)),*** was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term purchase method of accounting with acquisition method of accounting, SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141 s cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141 s guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination. The Company adopted SFAS No. 141(R) on January 1, 2009. The adoption did not have a material impact on its consolidated financial statements.

SFAS No. 161, ***Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,*** was issued by the FASB in March 2008. SFAS No. 161 requires enhanced disclosures about an entity s derivative and hedging activities to improve the transparency of financial reporting. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted SFAS No. 161 on January 1, 2009. Adoption of SFAS No. 161 resulted in additional footnote disclosures related to the Company s use of derivative instruments, the location and fair value of derivatives reported on the Company s consolidated balance sheets, the location and amounts of derivative instrument gains and losses reported on the Company s consolidated statements of income, and information on credit risk exposure related to derivative instruments.

FASB Staff Position (FSP) FAS 132(R)-1, ***Employers Disclosures about Postretirement Benefit Plan Assets,*** was issued by the FASB in December 2008. FSP FAS 132(R)-1 amends SFAS No. 132 (revised 2003), *Employers Disclosures about Pensions and Other Postretirement Benefits*, to expand an employer s required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. The Company does not expect the adoption of FSP FAS 132(R)-1 to have a material impact on its consolidated financial statements.

2. Segment Information

The Company s businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company (the electric utility). In addition, the electric utility is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. The electric utility operations have been the Company s primary business since incorporation.

Plastics consists of businesses producing polyvinyl chloride pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses in the following manufacturing activities: production of wind towers, contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays and horticultural containers. These businesses have manufacturing facilities in Florida, Illinois, Minnesota, Missouri, North Dakota, Oklahoma and Ontario, Canada and sell products primarily in the United States.

Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

Food Ingredient Processing consists of Idaho Pacific Holdings, Inc. (IPH), which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and 4 Canadian provinces.

Our electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation, and our energy services operation is operated as a subsidiary of Otter Tail Corporation. Substantially all of our other businesses are owned by our wholly owned subsidiary Varistar Corporation.

Corporate includes items such as corporate staff and overhead costs, the results of the Company s captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company s consolidated financial statements.

The Company has one customer within the Manufacturing segment that accounted for approximately 10.6% of the Company s consolidated revenues in 2008. No other single external customer accounts for 10% or more of the Company s revenues. Substantially all of the Company s long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

The following table presents the percent of consolidated sales revenue by country:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
United States of America	98.4%	96.1%
Canada	0.7%	1.2%
All Other Countries (none greater than 1%)	0.9%	2.7%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for three month periods ended March 31, 2009 and 2008 and total assets by business segment as of March 31, 2009 and December 31, 2008 are presented in the following tables:

Operating Revenue

(in thousands)	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Electric	$ 88,541	$ 97,590
Plastics	13,530	22,350
Manufacturing	96,019	97,595
Health Services	28,167	29,265
Food Ingredient Processing	20,086	15,898
Other Business Operations	31,895	38,110
Corporate Revenues and Intersegment Eliminations	(999)	(571)
Total	$277,239	$300,237

Interest Expense

(in thousands)	Three months ended March 31, 2009	Three months ended March 31, 2008
Electric	$4,011	$2,981
Plastics	200	141

Manufacturing	1,279	2,146
Health Services	96	179
Food Ingredient Processing	10	10
Other Business Operations	120	307
Corporate and Intersegment Eliminations	554	947
Total	$6,270	$6,711

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Income Taxes

(in thousands)	Three months ended March 31, 2009	2008
Electric	$ 1,771	$ 6,420
Plastics	(1,647)	425
Manufacturing	(804)	(603)
Health Services	(13)	(415)
Food Ingredient Processing	725	600
Other Business Operations	(206)	(1,160)
Corporate	(1,208)	(2,149)
Total	$(1,382)	$ 3,118

Earnings Available for Common Shares

(in thousands)	Three months ended March 31, 2009	2008
Electric	$ 8,342	$12,566
Plastics	(2,458)	620
Manufacturing	(1,090)	(616)
Health Services	(73)	(691)
Food Ingredient Processing	1,447	1,123
Other Business Operations	(325)	(1,765)
Corporate	(1,639)	(3,191)
Total	$ 4,204	$ 8,046

Total Assets

(in thousands)	March 31, 2009	December 31, 2008
Electric	$ 991,271	$ 992,159
Plastics	75,896	78,054
Manufacturing	338,877	356,697
Health Services	58,675	61,086
Food Ingredient Processing	87,459	88,813
Other Business Operations	69,165	71,359
Corporate	49,600	44,419
Total	$1,670,943	$1,692,587

3. Rate and Regulatory Matters

Minnesota

General Rate Case In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 the electric utility was granted an increase in Minnesota retail electric rates of $3.8 million or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $3.9 million had been recorded as a liability on the Company s consolidated balance sheet as of December 31, 2008. An additional $0.5 million refund liability was accrued in January 2009. The electric utility refunded Minnesota customers the difference between interim rates and final rates, with interest, in March 2009. The electric utility deferred recognition of $1.5 million in rate case-related filing and administrative costs in June 2008 that are subject to amortization and recovery over a three year period beginning in February 2009.

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Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need (MegaCON) On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kv) transmission lines. Evidentiary hearings for the Certificate of Need for the three CapX 2020 345-kv transmission line projects began in July 2008 and continued into August 2008. On April 16, 2009 the MPUC approved by a 5-0 vote the MegaCON for the three 345-kv Group 1 CapX 2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC then voted 3-2 to impose conditions pertaining to reserving line capacity for renewable energy sources on the Brookings line project. As part of the MegaCON approval, the MPUC accepted a CapX 2020 request to build the 345-kv lines for double-circuit capability to have two 345-kv transmission circuits on each structure. The current plan is to string only one circuit. Route permit applications were filed for the Brookings project in late December 2008 and for the Monticello-to-St. Cloud portion of the Fargo project in March 2009. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading these projects, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company is directly involved in two of these three projects.

Otter Tail Power Company serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kv line which has an expected in-service date of 2012-2013. The electric utility filed a Certificate of Need for this fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (MNOES) staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the Certificate of Need and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed the Certificate of Need and route permit applications were complete. The commissioners asked the CapX 2020 utilities to add a section to the Certificate of Need application addressing how the new Minnesota Conservation Improvement Programs statutes will affect the need for the project. Because no one has intervened in the Certificate of Need proceeding, the MPUC will handle the Certificate of Need application as an uncontested case. The MNOES subsequently recommended that need for the line has been established. The MPUC is expected to determine if there is a need for this line and, if appropriate, issue the route permit in spring 2010.

Renewable Energy Standards, Conservation, Renewable Resource and Transmission Riders In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. The electric utility has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. By the end of 2010, the electric utility expects to have sufficient renewable energy resources available to comply with the required 2012 level of the Minnesota renewable energy standard. The electric utility s compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007 passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

In an order issued on August 15, 2008, the MPUC approved the electric utility s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the electric utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment of 0.19 cents per kilowatt-hour (kwh) was included on Minnesota customers electric service statements beginning in September 2008. The first renewable energy project for which the electric utility is receiving cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility has recognized a regulatory asset of $3.7 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of March 31, 2009.

The electric utility is awaiting a decision from the MPUC on its 2009 Rider Adjustment filing. The 2009 Rider Adjustment filing includes a request for recovery of the electric utility s investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. The Minnesota Department of Commerce, Office of Energy Security and the Minnesota Chamber of Commerce intervened and opposed certain aspects of the Rider. The electric utility has replied to the intervenors position.

In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff rider to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility s retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility s last general rate case. The electric utility expects to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in 2009.

North Dakota

General Rate Case On November 3, 2008 the electric utility filed a general rate case in North Dakota requesting an overall revenue increase of approximately $6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. North Dakota Public Service Commission (NDPSC) advocacy staff and intervenors testimony were received in April 2009. Evidentiary Hearings, which were scheduled for the week of May 11, 2009, were suspended by the NDPSC at the request of the parties, pending finalization of a tentative settlement of the remaining issues in the case, the final terms of which have not been filed with the NDPSC. Finalizing, documenting and receiving a final decision by the NDPSC on the tentative settlement are expected by August 1, 2009. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes a final determination on the partial settlement and tentative settlement of the remaining issues. If final rates approved by the NDPSC are lower than interim rates, the electric utility will refund North Dakota customers the difference with interest.

Renewable Resource Cost Recovery Rider On May 21, 2008 the NDPSC approved the electric utility s request for a Renewable Resource Cost Recovery Rider to enable the electric utility to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The Renewable Resource Cost Recovery Rider Adjustment of 0.193 cents per kwh was included on North Dakota customers electric service statements beginning in June 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The electric utility has included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the Renewable Resource Cost Recovery Rider Adjustment. A Renewable Resource Cost Recovery Rider Adjustment rate of 0.51 cents per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009. In a proceeding being processed in combination with the electric utility s North Dakota Rate Case, the NDPSC is reviewing whether to move the costs of the projects currently being recovered through the rider into base rate cost recovery and whether to make changes to the rider. As described above, NDPSC advocacy staff and intervenors testimony were received in April 2009, and evidentiary hearings which were scheduled for the week of May 11, 2009 were suspended by the NDPSC at the request of the parties, pending finalization of a tentative settlement of the remaining issues in the case, the final terms of which have not yet been filed with the NDPSC. Finalizing, documenting and receiving a final decision by the NDPSC on the tentative settlement are expected by August 1, 2009.

The electric utility had not been deferring recognition of its renewable resource costs eligible for recovery under the North Dakota Renewable Resource Cost Recovery Rider but had been charging those costs to operating expense since January 2008. After approval of the rider in May 2008, the electric utility accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider. The Company s March 31, 2009 consolidated balance sheet includes a regulatory asset of $1.3 million for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but have not been billed to North Dakota customers as of March 31, 2009.

South Dakota

General Rate Case On October 31, 2008 the electric utility filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which includes recovery of renewable resource investments and expenses in base rates. The case s procedural schedule was suspended by the South Dakota Public Utilities Commission (SDPUC) at the request of the parties, pending finalization of a tentative settlement of the issues in the case, the final terms of which have not yet been filed with the SDPUC. Finalizing, documenting and receiving a final decision by the SDPUC on the tentative settlement are expected by July 1, 2009. The tentative settlement is subject to the approval of the SDPUC. South Dakota statutes allow for implementation of proposed rates 180 days after filing a general rate case. On April 21, 2009 the SDPUC granted the electric utility s request to implement interim rates in South Dakota, effective for consumption on and after May 1, 2009 using the revenue requirement and class allocations agreed to in the tentative settlement described above and existing rate design. In approving the interim rate methodology, however, the SDPUC did not make a final determination on the merits of the tentative settlement, and the interim rate increase is subject to refund with interest in the event the SDPUC approves a lower revenue requirement than is included in the tentative settlement. Interim rate increases will range from 6.1% for Bulk Interruptible Service to 39.4% for Controlled Service Interruptible Load Large Dual Fuel.

Federal

Revenue Sufficiency Guarantee (RSG) Charges Since 2006, the electric utility has been a party to litigation before the Federal Energy Regulatory Commission (FERC) regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC s orders are on review before the United States Court of Appeals for the district of Columbia Circuit (D.C. Circuit). These proceedings create potential contingent liabilities in three separate periods for the electric utility: (1) April 1, 2005 through April 24, 2006; (2) April 25, 2006 through August 9, 2007; and (3) August 10, 2007 forward. The electric utility identified and assessed potential contingent RSG liabilities under various scenarios depending on the time period over which the FERC ultimately orders RSG refunds. The electric utility accrued a liability in the fourth quarter of 2008 based on the outcome it determined to be most probable.

On November 10, 2008 the FERC issued an order on the paper hearing finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate. In response to RSG Compliance Order III, MISO made another compliance filing on December 8, 2008 in which it proposed to re-resettle the RSG charges and cost allocations back to market start to correct its previous resettlement completed in January 2008 that was based on the FERC s interpretation of the RSG rate and billing determinants affirmed in RSG III. In addition to correcting the RSG rate denominator to limit it to only virtual sales associated with actual physical energy withdrawals, MISO proposed additional corrections designed to reduce the denominator. Both changes would increase the RSG rate that the electric utility must pay. Also, on November 11, 2008 the FERC issued an order on rehearing of a November 28, 2007 order on complaint. Again, where the revenue from RSG charges collected is not sufficient to make RSG payments to suppliers, MISO recovers the shortage through an uplift charge from all load.

The electric utility requested rehearing of both November 2008 orders (in conjunction with the FERC s RSG Compliance Order III). The electric utility s principal concern in these proceedings was to ensure that the FERC did not impose refunds prior to the August 10, 2007 refund effective date. The FERC did not impose such refunds but did offer an interpretation in support of its decision in RSG Compliance Order III (in ER04-691 docket) that would subject the electric utility to further RSG refunds and resettlements prior to August 10, 2007. Several market participants filed an Emergency Motion and Emergency Request for Stay of the FERC s November 10, 2008 Order.

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On February 23, 2009 MISO filed its Redesign Proposal for allocation of RSG costs in compliance with the November 10, 2008 Order. MISO anticipates an effective date at or about the third quarter of 2009. The electric utility submitted a limited protest to ask that the FERC reject all portions of MISO s Compliance Filing that do not comply with its explicit directives in the November 10, 2008 Order (in particular the RSG rate denominator change). Also on February 23, 2009 the MISO Independent Market Monitor submitted a Findings and Recommendations report to the FERC arguing that the current implementation of the RSG rate is adversely affecting the MISO markets. Shortly thereafter, DC Energy and several other parties filed a Motion to Lodge in the RSG Complaint dockets in response to the February 27, 2009 decision of the D.C. Circuit in *City of Anaheim, California* v. *FERC.* In *City of Anaheim,* the Court held that the FERC cannot order retroactive rate increases under section 206 of the Federal Power Act (FPA). In their Motion to Lodge, the parties noted *City of Anaheim* should resolve the outcome of the refund issue pending before the FERC on rehearing in the RSG proceeding.

On April 28, 2009, a group of eight financial market participants filed a Writ of Mandamus with the D.C. Circuit. The group asked the court to require the FERC to act on the pending requests for rehearing, order MISO to stop issuing RSG invoices for previous periods, correct all past invoices, refund with interest amounts paid by the companies, and restore trading privileges for some of the companies. The Court acted on April 29, 2009, requiring the FERC to file a response to the complaint by May 7, 2009.

On May 6, 2009 the FERC issued an order granting rehearing on certain aspects of its November 10, 2008 Order. The order requires MISO to cease ongoing refunds and resettlements, as well as modify the effective date of the Interim Rate for RSG to November 10, 2008. Consistent with FERC s May 6, 2009 Order, MISO will cease the currently scheduled resettlements effective with Market Settlement Statements posted on May 8, 2009. Market Settlement Statements posted on May 7, 2009 will be the final statements containing resettlement charges.

Big Stone II Project

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant s nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules were established in the various project-related proceedings, which take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

In the fourth quarter of 2005, the participating utilities filed applications with the MPUC for a transmission Certificate of Need and a Route Permit for the Minnesota portion of the Big Stone II transmission line. On January 15, 2009 the MPUC approved, by a vote of 5-0, a motion to grant the Certificate of Need and Route Permit for the Minnesota portion of the Big Stone II transmission line. The motion involved numerous elements, including the following:

That there is reasonable assurance that Big Stone II would be more cost-effective than renewable energy beyond the statutory levels of renewable energy based on accepted estimates of construction costs and carbon dioxide;

That the 345 kv transmission project is necessary based on identified regional and state transmission needs; and

That the project presents risks requiring additional measures to protect the applicants ratepayers.

Therefore, the MPUC determined to grant the Certificate of Need subject to a number of additional conditions pending issuance of a final order, including but not limited to: (1) fulfilling various requirements relating to renewable energy goals, energy efficiency, community-based energy development projects and emissions reduction; (2) that the generation plant be built as a carbon capture retrofit ready facility; (3) that the applicants report to the MPUC on the feasibility of building the plant using ultra-supercritical technology; and (4) that the applicants achieve specific limits on construction cost at $3000/kilowatt (kW) and carbon dioxide costs at $26/ton.

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On March 17, 2009 the MPUC issued its written order reflecting the decision. While construction and carbon dioxide cost caps were not formal conditions of the certificate of need issuance, the MPUC s order notified the electric utility that the MPUC s present intention is to shield ratepayers from construction costs exceeding the $2,600 to $3,000/kW range and carbon regulation cost exceeding $26/ton adjusted for the passage of time, including inflation.

The applicants and intervenors subsequently filed petitions for reconsideration of the MPUC order. On April 30, 2009, the MPUC denied the petitions.

The Certificate of Need and Route Permit are required by state law and would allow the Big Stone II utilities to construct and upgrade 112 miles of electric transmission lines in western Minnesota for delivery of power from the Big Stone site and from numerous other planned generation projects, most of which are wind energy.

The electric utility s integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. On June 5, 2008 the MPUC deferred approval of the electric utility s 2006-2020 IRP, originally filed in 2005. The addition of 160 megawatts of wind generation in the IRP was approved early in 2007 and, on January 15, 2009, the MPUC approved the electric utility s 2006-2020 IRP in its entirety. As of the date of this report, the MPUC had not issued a written order reflecting its decision. This 2006-2020 IRP includes new renewable wind generation and significant demand-side management including conservation, new baseload including the proposed Big Stone II power plant, natural gas-fired peaking plants and wholesale energy purchases.

On August 27, 2008 the NDPSC determined that the electric utility s participation in Big Stone II was prudent in a range of 121.8 to 130 megawatts. The NDPSC decision has been appealed to Burleigh County District Court by interveners in the matter.

On November 20, 2008 the South Dakota Board of Minerals and Environment (Board) unanimously approved the Big Stone II participating utilities application for a Prevention of Significant Deterioration (PSD) permit for Big Stone II and a proposed Title V Operating Permit for the Big Stone site. A PSD permit is a pre-construction permit designed to protect air quality. Joint petitioners Sierra Club and Clean Water Action have appealed the administrative decision on the PSD permit to the Circuit Court of Hughes County. The appeal is currently pending before the Court. The issuance of the Title V permit is subject to review by the U.S. Environmental Protection Agency (EPA). On January 22, 2009, the EPA filed a formal objection to the proposed Title V permit. The State of South Dakota has revised and submitted a proposed permit in response to the EPA s objection. In a hearing before the Board held on April 20 and 21, 2009 in Pierre, South Dakota, the Board again directed issuance of the Title V permit if EPA does not object within its review period.

The Big Stone II federal Environmental Impact Statement (EIS) process led by the Western Area Power Administration (WAPA) continues to move forward. WAPA and its third party subcontractor continue to develop the Final EIS, which will include comments on the Draft EIS and the Supplemental Draft EIS, and responses to those comments. WAPA will develop a Record of Decision (ROD) following internal review and approval of the Final EIS. The electric utility anticipates publication of the ROD in the Federal Register in the second quarter of 2009. Financial close, which requires the participants to provide binding financial commitments to support their share of costs, is to occur 90 days after the EIS ROD. No one can predict the exact outcome of any of these proceedings.

The delays in approval of the Big Stone II transmission Certificate of Need in Minnesota and issuance of required permits may delay the availability of Big Stone II as a generation resource. Also, the electric utility has experienced more rapid load growth than was expected since originally filing the IRP in 2005. The electric utility is assessing ways in which to address this potential near-term generation shortfall and has received approval from the MPUC to immediately acquire up to 110 megawatts of peaking capacity.

As of March 31, 2009 the electric utility has capitalized $11.9 million in costs related to the planned construction of Big Stone II. If the project is abandoned for permitting or other reasons, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

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4. Regulatory Assets and Liabilities

As a regulated entity the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71, Accounting for the Effect of Certain Types of Regulation. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

The following table indicates the amount of regulatory assets and liabilities recorded on the Company s consolidated balance sheet:

(in thousands)	March 31, 2009	December 31, 2008
Regulatory Assets:		
Unrecognized Prior Service Costs and Actuarial Losses on Pension Benefits	$64,117	$64,490
Deferred Income Taxes	7,094	7,094
Accrued Cost-of-Energy Revenue	4,481	8,982
Minnesota Renewable Resource Rider Accrued Revenues	3,679	3,045
Debt Reacquisition Premiums	3,274	3,357
Accumulated ARO Accretion/Depreciation Adjustment	1,516	1,437
Minnesota General Rate Case Recoverable Expenses	1,376	1,457
North Dakota Renewable Resource Rider Accrued Revenues	1,332	2,009
MISO Schedule 16 and 17 Deferred Administrative Costs ND	755	823
MISO Schedule 16 and 17 Deferred Administrative Costs MN	458	526
Deferred Marked-to-Market Losses	102	1,162
Plant Acquisition Costs	52	63
Deferred Conservation Improvement Program Costs	(63)	280
Total Regulatory Assets	$88,173	$94,725
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$59,093	$58,768
Deferred Income Taxes	4,773	4,943
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	958	834
Gain on Sale of Division Office Building	138	139
Total Regulatory Liabilities	$64,962	$64,684
Net Regulatory Asset Position	$23,211	$30,041

The regulatory asset related to prior service costs and actuarial losses on pension benefits and the regulatory liability related to the unrecognized transition obligation, prior service costs and actuarial gains on other postretirement benefits represents benefit costs and actuarial gains subject to recovery or return through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial gains were required to be recognized as components of Accumulated Other Comprehensive Income in equity under SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans,* but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*.

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 17 months.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers since January 1, 2008 that have not been billed to Minnesota customers as of March 31, 2009. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 12 months, from April 2009 through March 2010.

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Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 23.5 years.
The Accumulated ARO Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.
Minnesota General Rate Case Recoverable Expenses will be recovered over the next 34 months.
North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve North Dakota customers since January 1, 2008 that have not been billed to North Dakota customers as of March 31, 2009. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 10 months, from April 2009 through January 2010.
MISO Schedule 16 and 17 Deferred Administrative Costs ND will be recovered over the next 33 months.
MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 20 months.
All Deferred Marked-to-Market Losses recorded as of March 31, 2009 are related to forward purchases of energy scheduled for delivery in April 2009.
Plant Acquisition Costs will be amortized over the next 14 months.
Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 15 months.
The Accumulated Reserve for Estimated Removal Costs is reduced as actual removal costs are incurred.
The remaining regulatory liabilities will be paid to electric customers over the next 30 years.
If for any reason, the Company s regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts

All of the electric utility s wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. The electric utility s objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. The electric utility s intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. The electric utility also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.
As of March 31, 2009 the electric utility had recognized, on a pretax basis, $692,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility s power services personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in SFAS No. 157.

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The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company s consolidated balance sheets as of March 31, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to March 31, 2009:

(in thousands)	March 31, 2009	December 31, 2008
In Other Current Assets Marked-to-Market Gain	$ 3,159	$ 405
In Regulatory Assets and Other Deferred Debits Deferred Marked-to-Market Loss	102	1,162
In Other Accrued Current Liabilities Marked-to-Market Loss	(2,569)	(1,690)
Net Fair Value of Marked-to-Market Energy Contracts	$ 692	$ (123)

(in thousands)	Year-to-Date March 31, 2009
Fair Value at Beginning of Year	$ (123)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	123
Changes in Fair Value of Contracts Entered into in 2008	
Net Fair Value of Contracts Entered into in 2008 at End of Period	
Changes in Fair Value of Contracts Entered into in 2009	692
Net Fair Value End of Period	$ 692

Realized and unrealized net gains on forward energy contracts of $1,034,000 for the three months ended March 31, 2009 and $2,250,000 for the three months ended March 31, 2008 are included in electric operating revenues on the Company s consolidated statements of income.

The electric utility has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy purchases and sales agreements. The electric utility has established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty s financial strength. The credit risk with the largest counterparty on delivered and marked-to-market forward contracts as of March 31, 2009 was $2,200,000. As of March 31, 2009 the net credit risk exposure was $7,381,000 from twelve counterparties with investment grade credit ratings and four counterparties that have not been rated by an external credit rating agency but have been evaluated internally and assigned an internal credit rating equivalent to investment grade. The electric utility had no exposure at March 31, 2009 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor s), Baa3 (Moody s) or BBB- (Fitch). The $7,381,000 credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after March 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

The mark-to-market losses of certain of the Company s derivative energy contracts included in the $2,569,000 derivative liability on March 31, 2009 are covered by deposited funds. The aggregate fair value of these derivatives on March 31, 2009, is $1,225,000. Certain other of the Company s derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on the Company s debt. If the

Company s debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request immediate and ongoing full overnight collateralization on contracts in net liability positions. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that are in a liability position on March 31, 2009, is $128,000, for which the Company has posted $128,000 in the form of offsetting gain positions on other contracts with the counterparties under master netting agreements. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2009, the Company would not be required to post any additional collateral to its counterparties.

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Fuel Contracts

In order to limit its exposure to fluctuations in future prices of natural gas and fuel oil, IPH entered into contracts with its fuel suppliers in August 2008 and January 2009 for firm purchases of natural gas and fuel oil to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 and its fuel oil needs in Souris, Prince Edward Island, Canada from January 2009 through August 2009 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under SFAS 133, as amended by SFAS 138.

Foreign Currency Exchange Forward Windows

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH s Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. The following table lists the contracts outstanding as of March 31, 2009:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in July 2008	April 2009 - July 2009	$1,600	$1,668
Contracts entered into in October 2008	April 2009 - October 2009	2,800	3,499
Contracts outstanding on March 31, 2009	April 2009 - October 2009	$4,400	$5,167

The following tables show the effect of marking to market IPH s foreign currency exchange forward windows and the location and fair value amounts of the related derivatives reported on the Company s consolidated balance sheets as of March 31, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to March 31, 2009:

(in thousands)	March 31, 2009	December 31, 2008
Fair Value of IPH Foreign Currency Exchange Forward Windows included in Other Accrued Current Liabilities	$ (295)	$ (289)

(in thousands)	Year-to-Date March 31, 2009
Fair Value at Beginning of Year	$ (289)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	138
Changes in Fair Value of Contracts Entered into in 2008	(144)
Net Fair Value of Contracts Entered into in 2008 at End of Period	(295)
Changes in Fair Value of Contracts Entered into in 2009	

Net Fair Value End of Period	$ (295)

These contracts are derivatives subject to mark-to-market accounting. IPH does not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates with the intent of settling these contracts during their stated settlement periods and using the proceeds to pay its Canadian liabilities when they come due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements did not and will not coincide with the payment of specific bills or existing contractual obligations. The foreign currency exchange forward contracts outstanding as of March 31, 2009 were valued and marked to market on March 31, 2009 based on quoted exchange values on March 31, 2009. Realized and unrealized net losses on IPH s foreign currency exchange forward windows of $6,000 for the three months ended March 31, 2009, are included in other income on the Company s consolidated statements of income.

The fair value measurements of the above foreign currency exchange forward windows fall into level 1 of the fair value hierarchy set forth in SFAS No. 157.

6. Common Shares and Earnings Per Share

Following is a reconciliation of the Company s common shares outstanding from December 31, 2008 through March 31, 2009:

Common Shares Outstanding, December 31, 2008	35,384,620
Issuances:	
Executive Officer Stock Performance Awards	29,350
Stock Options Exercised	1,350
Vesting of Restricted Stock Units	1,000
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(7,187)
Common Shares Outstanding, March 31, 2009	35,409,133

Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company s directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the quarters ended March 31, 2009 and 2008:

Quarter Ended March 31,	Options Outstanding	Range of Exercise Prices
2009	420,460	\$24.93 \$31.34
2008		NA

7. Share-Based Payments

The Company has five share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2009. As of March 31, 2009 the remaining unrecognized compensation expense related to stock-based compensation was approximately \$5.0 million (before income taxes) which will be amortized over a weighted-average period of 2.0 years.

Amounts of compensation expense recognized under the Company s five stock-based payment programs for the three months ended March 31, 2009 and 2008 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2009	2008
Employee Stock Purchase Plan (15% discount)	\$ 90	\$ 70
Restricted Stock Granted to Directors	111	108
Restricted Stock Granted to Employees	91	118
Restricted Stock Units Granted to Employees	121	94

Stock Performance Awards Granted to Executive Officers	435	340
Totals	$848	$730

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9. Commitments and Contingencies

Electric Utility Coal Contract

In March 2009, the electric utility entered into an agreement for the purchase of coal to cover a portion of its current coal requirements in 2009 and 2010 with a minimum purchase commitment totaling approximately $9,500,000. The Fuel Clause Adjustment mechanism in retail electric rates lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

Dealer Floor Plan Financing

Under ShoreMaster s floor plan financing agreement with GE Commercial Distribution Finance Corporation (CDF), ShoreMaster is required to repurchase new and unused inventory repossessed from ShoreMaster s dealers by CDF to satisfy dealer obligations to CDF. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.8 million on March 31, 2009. ShoreMaster has incurred no losses under this agreement. The Company believes current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement. CDF exercised its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement has no affect on ShoreMaster s obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for any expenses incurred by CDF after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement.

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleged the defendants actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the U.S. District Court for the District of South Dakota (Northern Division) issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration will stay the deadline for the Sierra Club to appeal dismissal of its complaint. The ultimate outcome of these matters cannot be determined at this time.

Product Recall

Aviva Sports, Inc. (Aviva), a subsidiary of ShoreMaster, markets a variety of consumer products to catalog companies and internet based retailers. Some of these products are regulated by the U.S. Consumer Product Safety Commission (CPSC). On February 3, 2009 Aviva received a report of consumer contacts from a catalog customer related to one of Aviva s trampoline products. Aviva has not received any personal injury claims or lawsuits related to this product. Aviva submitted notification of the complaints to the CPSC and voluntarily agreed to undertake a recall of approximately 12,000 of the trampoline products. ShoreMaster recorded a liability and operating expense of $1.4 million related to the recall in the first quarter of 2009. The expense includes a projected 50% customer response rate on the recall request, fees to the third party recall administrator, costs to destroy inventory and all legal and administration fees. The customer response rate was 36% as of the end of April 2009.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of March 31, 2009 will not be material.

11. Class B Stock Options of Subsidiary

As of March 31, 2009 there were 912 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $683,000, of which 732 options were in-the-money with a combined exercise price of $307,000.

12. Pension Plan and Other Postretirement Benefits

Pension Plan Components of net periodic pension benefit cost of the Company s noncontributory funded pension plan are as follows:

	Three Months Ended March 31,	
(in thousands)	2009	2008
Service Cost Benefit Earned During the Period	$ 1,133	$ 1,275
Interest Cost on Projected Benefit Obligation	2,975	2,800
Expected Return on Assets	(3,448)	(3,550)
Amortization of Prior-Service Cost	181	175
Amortization of Net Actuarial Loss	5	125
Net Periodic Pension Cost	$ 846	$ 825

The Company did not make a contribution to its pension plan in the three months ended March 31, 2009 and is not currently required to make a contribution in 2009.

Executive Survivor and Supplemental Retirement Plan Components of net periodic pension benefit cost of the Company s unfunded, nonqualified benefit plan for executive officers and certain key management employees are as follows:

	Three Months Ended March 31,	
(in thousands)	2009	2008
Service Cost Benefit Earned During the Period	$188	$173
Interest Cost on Projected Benefit Obligation	424	384
Amortization of Prior-Service Cost	18	16
Amortization of Net Actuarial Loss	96	120
Net Periodic Pension Cost	$726	$693

Postretirement Benefits Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired electric utility and corporate employees are as follows:

	Three Months Ended March 31,	
(in thousands)	2009	2008
Service Cost Benefit Earned During the Period	$ 301	$ 300

Interest Cost on Projected Benefit Obligation	753	725
Amortization of Transition Obligation	187	187
Amortization of Prior-Service Cost	53	50
Amortization of Net Actuarial Loss	1	125
Effect of Medicare Part D Expected Subsidy	(297)	(400)
Net Periodic Postretirement Benefit Cost	$ 998	$ 987

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15. Income Taxes

The Company s effective income tax rate for the three months ended March 31, 2009 and 2008 was approximately (46.0%) and 27.5%, respectively. The reduction from the federal statutory rate mainly reflects the benefit of production tax credits (PTCs) and North Dakota wind energy credits related to the electric utility s wind projects of approximately $2.1 million in the first of quarter of 2009 and $0.6 million in the first quarter of 2008.

The Company recognizes PTCs as wind energy is generated and sold based on a per kilowatt-hour rate prescribed in applicable federal statutes, which may differ significantly from amounts computed, on a quarterly basis, using an overall effective income tax rate anticipated for the full year. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years. The Company utilizes this method of recognizing PTCs for specific reasons, including that PTCs are an integral part of the financial viability of most wind projects and a fundamental component of such wind projects results of operations.

19. Subsequent Events

On April 20, 2009 the Company s Board of Directors granted 29,515 restricted stock units to key employees under the 1999 Stock Incentive Plan, as amended (Incentive Plan), payable in common shares on April 8, 2013, the date the units vest. The grant date fair value of each restricted stock unit was $18.86 per share determined under a Monte Carlo valuation method based on the market value of the Company s common stock on April 20, 2009.

On April 20, 2009 the Company s Board of Directors granted 28,800 shares of restricted stock to the Company s nonemployee directors and 27,600 shares of restricted stock to the Company s executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2010 through 2013 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.15 per share, the average market price on the date of grant.

On April 20, 2009 the Company s Board of Directors granted performance share awards to the Company s executive officers under the Incentive Plan. Under these awards, the Company s executive officers could earn up to an aggregate of 181,200 common shares based on the Company s total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance period of January 1, 2009 through December 31, 2011. The aggregate target share award is 90,600 shares. Actual payment may range from zero to 200% of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The grant date fair value of the target amount common shares projected to be awarded was $27.76 per share, as determined under a Monte Carlo valuation method. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under SFAS No. 123(R), and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

On May 1, 2009 the Company received a federal income tax refund of $26.4 million related to the carry-back of 2008 tax credits and net operating losses for tax purposes to prior years.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three months ended March 31, 2009 and 2008, followed by our outlook for the remainder of 2009 and a discussion of changes in our consolidated financial position during the three months ended March 31, 2009.

Comparison of the Three Months Ended March 31, 2009 and 2008

Consolidated operating revenues were $277.2 million for the three months ended March 31, 2009 compared with $300.2 million for the three months ended March 31, 2008. Operating income was $8.6 million for the three months ended March 31, 2009 compared with $17.1 million for the three months ended March 31, 2008. The Company recorded diluted earnings per share of $0.12 for the three months ended March 31, 2009 compared to $0.27 for the three months ended March 31, 2008.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended March 31, 2009 and 2008 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	March 31, 2009	March 31, 2008
Operating Revenues:		
Electric	$ 62	$ 85
Nonelectric	938	486
Cost of Goods Sold	840	466
Other Nonelectric Expenses	160	105

Electric

(in thousands)	Three Months Ended March 31, 2009	2008	Change	% Change
Retail Sales Revenues	$79,055	$87,300	$(8,245)	(9.4)
Wholesale Revenues	4,763	3,584	1,179	32.9
Net Marked-to-Market Gain	1,034	2,250	(1,216)	(54.0)
Other Revenues	3,689	4,456	(767)	(17.2)
Total Operating Revenues	$88,541	$97,590	$(9,049)	(9.3)
Production Fuel	18,659	19,904	(1,245)	(6.3)
Purchased Power System Use	17,373	18,986	(1,613)	(8.5)
Other Operation and Maintenance Expenses	26,930	26,743	187	0.7
Depreciation and Amortization	8,988	7,708	1,280	16.6
Property Taxes	2,490	2,624	(134)	(5.1)
Operating Income	$14,101	$21,625	$(7,524)	(34.8)

The main reason for the decline in retail sales revenue was a $9.7 million decrease in fuel cost recovery revenues mainly related to a decrease in costs per kilowatt-hour (kwh) for fuel and purchased power between the quarters. Other items affecting retail sales revenue were a reduction in Minnesota retail revenues of $1.5 million related to adjustments to final rate components and a final Minnesota rate increase of 2.9% in effect in the first quarter of 2009 compared to an interim rate increase of 5.4% in effect in the first quarter of 2008, and a 10.6% decrease in kwh sales to industrial customers due to reduced demand by pipeline customers as a result of declining oil and natural gas prices. These retail sales revenue decreases were partially offset by a $1.5 million increase in revenues related to increases in kwh sales to residential and commercial customers, increases in renewable resource recovery rider revenues totaling $1.5 million and a 4.1% interim rate increase in North Dakota implemented in the first quarter of 2009.

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Wholesale electric revenues from sales from company-owned generation were $4.4 million for the quarter ended March 31, 2009 compared with $4.1 million for the quarter ended March 31, 2008 as a result of a 97.5% increase in wholesale kwh sales offset by a 46.2% decrease in the average price per kwh. Fuel costs related to wholesale sales increased $0.4 million between the quarters as a result of the increase in wholesale kwh sales. Reductions in industrial consumption of electricity, declining natural gas prices and increased generation from renewable wind and hydroelectric resources have driven down prices for electricity in the wholesale market. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $1.4 million for the quarter ended March 31, 2009 compared with $1.7 million for the quarter ended March 31, 2008. The $0.8 million decrease in other electric operating revenues includes a $0.6 million decrease in revenues from contracted services and a $0.2 million reduction in transmission services related revenue.

The decrease in fuel costs reflects an 8.0% decrease in kwhs generated from the electric utility s fuel-fired plants, partially offset by a 1.9% increase in the cost of fuel per kwh generated. A 9.6% increase in the average cost of fuel per kwh of generation at the electric utility s coal-fired plants was partially offset by a 39.1% decrease in the average cost of fuel per kwh of generation at the electric utility s natural gas and fuel-oil-fired combustion turbines. Fuel costs were also reduced as a result of wind turbines owned by the electric utility providing 9.0% of total kwh generation in the first quarter of 2009. Generation for retail sales decreased 6.8% while generation used for wholesale electric sales increased 97.5% between the quarters.

The decrease in purchased power system use is due to a 36.5% reduction in the cost per mwh purchased offset by a 44.1% increase in mwhs purchased. The increase in mwh purchases for system use is, in part, related to a decrease in mwhs generated at company-owned plants but is also partly due to the dramatic decreases in wholesale electric prices. The decrease in the cost per kwh of purchased power reflects a significant decrease in fuel and purchased power costs across the Mid-Continent Area Power Pool region as a result of recent reductions in industrial consumption of electricity related to the current economic recession, declining natural gas prices and the availability of increased generation from renewable wind and hydroelectric.

Electric operating and maintenance expenses were essentially unchanged between the quarters. Depreciation expenses increased $1.3 million as a result of 2008 capital additions, including 32 new wind turbines at the Ashtabula Wind Energy Center.

Plastics

	Three Months Ended March 31,			
(in thousands)	2009	2008	Change	% Change
Operating Revenues	$13,530	$22,350	$(8,820)	(39.5)
Cost of Goods Sold	15,352	18,936	(3,584)	(18.9)
Operating Expenses	1,375	1,438	(63)	(4.4)
Depreciation and Amortization	716	795	(79)	(9.9)
Operating (Loss) Income	$ (3,913)	$ 1,181	$(5,094)	(431.3)

Operating revenues for the plastics segment decreased as result of an 18.8% decrease in pounds of pipe sold combined with a 25.2% decrease in polyvinyl chloride (PVC) pipe prices. The decrease in costs of goods sold was due to the decrease in pounds of pipe sold. The lower profitability between the quarters was also impacted by the sell-off of higher priced finished goods inventory which adversely impacted operating margins. Significant reductions in new home construction in markets served by the plastic pipe companies have resulted in reduced demand and lower prices for PVC pipe products.

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Manufacturing

(in thousands)	Three Months Ended March 31, 2009	2008	Change	% Change
Operating Revenues	$96,019	$97,595	$(1,576)	(1.6)
Cost of Goods Sold	79,535	82,848	(3,313)	(4.0)
Operating Expenses	10,046	10,323	(277)	(2.7)
Product Recall and Testing Costs	1,766		1,766	
Depreciation and Amortization	5,358	3,749	1,609	42.9
Operating (Loss) Income	$ (686)	$ 675	$(1,361)	(201.6)

The decrease in revenues in our manufacturing segment relates to the following:

Revenues at DMI Industries, Inc. (DMI) increased $1.7 million as a result of increased production of tower units at its Tulsa plant, which began production in the first quarter of 2008.

Revenues at BTD Manufacturing, Inc. (BTD) increased $3.8 million. The increase reflects first quarter 2009 revenues of $5.2 million from Miller Welding, acquired in May 2008, offset by a $0.7 million decrease in sales volume and a $0.6 million decrease in scrap sales revenue related to a decrease in steel prices.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) decreased $4.6 million due to a decrease in horticultural product sales as customers utilized existing inventory in the channel.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $2.5 million mainly due to decreased sales of residential products related to current economic uncertainty and credit restraints resulting in reduced orders from dealers.

The decrease in cost of goods sold in our manufacturing segment relates to the following:

DMI s cost of goods sold decreased $2.5 million as a result of productivity improvements at DMI s Tulsa plant and a reduction in costs at the Fort Erie plant. Included in cost of goods sold for the quarter ended March 31, 2008 were costs of $0.8 million associated with the start up of DMI s Tulsa plant and $3.2 million in additional labor and material costs on a production contract at the Fort Erie plant.

Cost of goods sold at BTD increased $4.7 million. The increase reflects first quarter 2009 costs of $3.9 million at Miller Welding, acquired in May 2008 and sales of higher cost items from inventory produced in 2008.

Cost of goods sold at T.O. Plastics decreased $3.8 million as a result of decreased sales of horticultural products.

Cost of goods sold at ShoreMaster decreased $1.7 million mainly due to the decrease in sales of residential products partially offset by $0.9 million in additional costs on a large marina project.

The net increase in operating expenses, including product recall and testing costs, in our manufacturing segment is due to the following:

Operating expenses at DMI increased $0.3 million, mainly as a result of first quarter 2009 fees and expenses related to DMI s accounts receivable sales agreement initiated in the second quarter of 2008.

BTD s operating expenses increased $0.2 million mainly as a result of the acquisition of Miller Welding in May 2008.

ShoreMaster s operating expenses, including product recall and testing costs, increased $1.1 million as a result of the recognition of $1.4 million in costs related to the recall of certain trampoline products and $0.4 million in costs to test imported products for lead/phthalate content, offset by reductions of $0.5 million in labor and benefit expenses and $0.2 million in expenditures for professional services.

T.O. Plastics operating expenses were down $0.1 million between the quarters.

Depreciation expense increased as a result of capital additions at DMI and the acquisition of Miller Welding in May 2008.

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Health Services

(in thousands)	Three Months Ended March 31, 2009	2008	Change	% Change
Operating Revenues	$28,167	$29,265	$(1,098)	(3.8)
Cost of Goods Sold	22,137	23,291	(1,154)	(5.0)
Operating Expenses	5,089	5,925	(836)	(14.1)
Depreciation and Amortization	990	982	8	0.8
Operating (Loss)	$ (49)	$ (933)	$ 884	94.7

Revenues from scanning and other related services were down $0.9 million and revenues from equipment sales and servicing decreased $0.2 million for the three months ended March 31, 2009 compared with the three months ended March 31, 2008. The decrease in cost of goods sold was directly related to the decreases in sales revenue. Measures taken to control and reduce operating expenses have resulted in the reduction in operating losses in the health services segment between the quarters. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

Food Ingredient Processing

(in thousands)	Three Months Ended March 31, 2009	2008	Change	% Change
Operating Revenues	$20,086	$15,898	$4,188	26.3
Cost of Goods Sold	15,982	12,319	3,663	29.7
Operating Expenses	812	813	(1)	(0.1)
Depreciation and Amortization	1,041	1,073	(32)	(3.0)
Operating Income	$ 2,251	$ 1,693	$ 558	33.0

The increase in food ingredient processing revenues is due to a 7.6% increase in pounds of product sold, combined with a 17.4% increase in the price per pound of product sold. Cost of goods sold increased as a result of the increase in sales and a 20.5% increase in the cost per pound of product sold.

Other Business Operations

(in thousands)	Three Months Ended March 31, 2009	2008	Change	% Change
Operating Revenues	$31,895	$38,110	$(6,215)	(16.3)
Cost of Goods Sold	20,795	28,295	(7,500)	(26.5)
Operating Expenses	10,861	12,013	(1,152)	(9.6)
Depreciation and Amortization	624	461	163	35.4
Operating Loss	$ (385)	$ (2,659)	$ 2,274	85.5

The decrease in revenues in the other business operations segment relates to the following:

Revenues at Midwest Construction Services, Inc. (MCS) decreased $2.7 million as a result of a decrease in jobs in progress, especially wind-energy projects, related to the current economic recession and tight credit.

Revenues at Foley Company decreased $1.4 million due to a decrease in volume of jobs in progress.

Revenues at E.W. Wylie Corporation (Wylie) decreased $2.1 million due to a 30.1% reduction in miles driven by company-owned trucks and a 4.5% decrease in miles driven by owner-operated trucks directly related to the current economic recession.

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The decrease in cost of goods sold in the other business operations segment relates to the following:

Cost of goods sold at MCS decreased $4.2 million, mainly due to decreases in material, subcontractor and labor costs related to a reduction of jobs in progress.

Foley Company s cost of goods sold decreased $3.3 million, including decreases of $2.5 million in material costs and $0.7 million in subcontractor costs, as a result of decreased construction activity and jobs in progress.

The decrease in operating expenses in the other business operations segment is due to the following:

Wylie s operating expenses decreased $1.3 million between the quarters. Fuel costs decreased $1.1 million as a result of the decrease in miles driven by company-owned trucks. Subcontractor expenses decreased $0.5 million as a result of the decrease in miles driven by owner-operated trucks. Equipment rental costs increased by $0.2 million due to the leasing of additional equipment.

MCS s operating expenses increased $0.3 million between the quarters mainly due to increased labor expenses.

Operating expenses at Foley Company were flat between the quarters.

Corporate

Corporate includes items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

	Three Months Ended March 31,			%
(in thousands)	2009	2008	Change	Change
Operating Expenses	$2,610	$4,340	$(1,730)	(39.9)
Depreciation and Amortization	100	145	(45)	(31.0)

The decrease in corporate operating expenses reflects reductions for salaries and benefits and professional and contracted services.

Interest Charges

Interest charges decreased $0.4 million in the first three months of 2009 compared with the first three months of 2008 as a result of decreases in short-term debt interest rates and a decrease in average long-term debt outstanding between the quarters.

Other Income

Other income decreased $0.3 million in the first three months of 2009 compared with the first three months of 2008 as a result of a decrease in allowance for funds used during construction (AFUDC) at the electric utility.

Income Taxes

The $4.5 million decrease in income taxes between the quarters is primarily the result of an $8.3 million (73.5%) decrease in income before income taxes for the three months ended March 31, 2009 compared with the three months ended March 31, 2008. The effective tax rate for the three months ended March 31, 2009 was (46.0%) compared with 27.5% for the three months ended March 31, 2008. The reduction from the federal statutory rate mainly reflects the benefit of federal production tax credits and North Dakota wind energy credits related to the electric utility s wind projects of approximately $2.1 million in the first quarter of 2009 compared with $0.6 million in the first quarter of 2008. Federal production tax credits are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

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2009 EXPECTATIONS

The statements in this section are based on our current outlook for 2009 and are subject to risks and uncertainties described under Forward Looking Information Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995.

We are revising our 2009 earnings guidance to be in a range of $0.80 to $1.20 per diluted share from our previously announced range of $1.10 to $1.50. The earnings guidance revision is reflective of our expectations that difficult economic conditions will continue for the balance of the year. The revised earnings guidance is subject to risks and uncertainties given current global economic conditions and the other risk factors outlined below.

Contributing to the earnings guidance for 2009 are the following items:

Our expectations for earnings from our electric segment have been revised downward due to the negative impact from continuing softness in demand from commercial and industrial customers and lower volumes and margins from wholesale energy sales. Declining demand along with the lowest natural gas prices in years is having a dramatic impact on the volume and price that can be realized from sales of excess generation into the marketplace. As a result, we now expect earnings from our electric segment to be lower in 2009 than in 2008. We still expect increased levels of retail revenue from the electric segment in 2009 as a result of a 4.1% interim rate increase in North Dakota and increases in resource recovery rider revenue related to the Ashtabula Wind Energy Center that was placed in service in late 2008. The interim rate increase is part of a rate case filed with the North Dakota Public Service Commission (NDPSC) in November 2008 requesting a general annual rate increase of approximately $6.1 million, or 5.1%. Interim rates remain in effect for all North Dakota customers until the NDPSC makes a final determination on the electric utility s request, which is expected to occur by August 1, 2009. Expectations in 2009 also reflect a request for an increase in revenues in South Dakota. A final decision on the request is expected from the South Dakota Public Utilities Commission in mid-summer 2009 with an interim rate increase going into effect in May 2009.

We expect the plastics segment s 2009 performance to be below 2008 earnings given continued poor economic conditions. Previously announced capacity expansions are not expected to be brought on line until the economy improves and demand for PVC pipe increases.

We now expect earnings from the manufacturing segment to decline in 2009 as a result of the following:

- BTD saw unanticipated declines in customer demand in the first quarter of 2009 and expects the soft demand to continue for the rest of the year resulting in lower earnings compared with 2008.

- While the economy is expected to reduce the amount of spending on waterfront products, earnings are expected to improve at ShoreMaster compared with 2008 given the restructuring that has occurred in its business. While there continues to be uncertainty on the level of spending on residential products, ShoreMaster has implemented significant cost reductions across the organization, reduced capital spending and reorganized its business units for more efficient operations.

- At DMI, we expect a decline in earnings in 2009 due to wind developers limited access to financing which has resulted in delays or suspension of orders across the industry. Industry forecasts for megawatt installations of wind power in 2009 indicate a decrease of between 25 to 50 percent from 2008.

- T. O. Plastics earnings are expected to remain flat between the years. While it expects economic challenges, T.O. Plastics has implemented cost reductions and efficiency projects to maintain profitability.

- Backlog in place in the manufacturing segment to support revenues for the remainder of 2009 is approximately $152 million compared with $280 million one year ago.

We expect increased net income from our health services segment in 2009 as it focuses on improving its mix of imaging assets and asset utilization rates and has implemented cost reductions across the segment.

We expect increased net income from our food ingredient processing business in 2009 based on expectations of higher sales volumes, strong pricing for products, lower energy costs and higher production levels in 2009 compared with 2008.

We expect our other business operations segment to have a similar level of earnings in 2009 compared with 2008.

Backlog in place for the construction businesses is $85 million for the remainder of 2009 compared with $83 million one year ago.

We expect corporate general and administrative costs to decrease in 2009.

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FINANCIAL POSITION

The following table presents the status of our lines of credit as of March 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on March 31, 2009	Restricted due to Outstanding Letters of Credit	Available on March 31, 2009	Available on December 31, 2008
Varistar Credit Agreement	$200,000	$116,747	$ 14,445	$ 68,808	$ 77,706
Electric Utility Credit Agreement	170,000	32,316		137,684	142,935
Total	$370,000	$149,063	$ 14,445	$206,492	$220,641

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if current market conditions continue. Despite the continuing economic recession, our balance sheet is strong and we are in compliance with our debt covenants. Our dividend payout ratio for the year ended December 31, 2008, was 109% compared to 66% and 68% for the years ended December 31, 2007 and 2006, respectively. Our current indicated annual dividend would result in a dividend per share of $1.19 in 2009. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of solid credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. Equity or debt financing will be required in the period 2009 through 2013 given the expansion plans related to our electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Our wholly owned subsidiary, Varistar Corporation (Varistar), has a $200 million credit agreement (the Varistar Credit Agreement) with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 2.0%, subject to adjustment based on Varistar s adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million.

Otter Tail Corporation, dba Otter Tail Power Company has a $170 million credit agreement (the Electric Utility Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as described in the credit agreement. The credit agreement is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

The note purchase agreement relating to our $90 million 6.63% senior notes due December 1, 2011, as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to our $50 million 5.778% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), and the note purchase agreement relating to our $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, as amended (the 2007 Note Purchase Agreement) each states we may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require us to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states we must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement each contain a number of restrictions on us and our subsidiaries. These include restrictions on our ability and the ability of our subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of our subsidiaries.

Financial Covenants

Our Electric Utility Credit Agreement, 2001 Note Purchase Agreement, Cascade Note Purchase Agreement, 2007 Note Purchase Agreement, Lombard US Equipment Finance Note and financial guaranty insurance policy with Ambac Assurance Corporation relating to our pollution control refunding bonds contain covenants by us to not permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest coverage ratio) to be less than 1.5 to 1. On effectiveness of the Permitted Reorganization, the Varistar Credit Agreement will contain similar covenants applicable to the new holding company. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. The Varistar Credit Agreement also contains certain financial covenants that will apply to Varistar until the effectiveness of the Permitted Reorganization. Specifically, Varistar must maintain a fixed charge coverage ratio (as defined in the Varistar Credit Agreement) of not less than 1.20 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, and not less than 1.25 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. In addition, Varistar must not permit its Cash Flow Leverage Ratio (as defined in the Varistar Credit Agreement) to exceed 3.25 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, or to exceed 3.00 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. Our Credit and Note Purchase Agreements do not contain any provisions that would trigger an acceleration of our debt caused by credit rating levels assigned to us by rating agencies. We and Varistar were in compliance with all of the financial covenants under our respective financing agreements as of March 31, 2009.

Our securities ratings at March 31, 2009 were:

	Moody's Investors Service	Standard

		& Poor's
Senior Unsecured Debt	A3	BBB-
Preferred Stock	Not rated	BB
Outlook	Negative	Stable

Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further, downgrades could increase our borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

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In March 2008, DMI entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $38.8 million were sold in the first quarter of 2009. Discounts, fees and commissions of $175,000 for the three months ended March 31, 2009 were charged to operating expenses in the consolidated statements of income. The balance of receivables sold that was outstanding to the buyer as of March 31, 2009 was $22.8 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

In December 2007, ShoreMaster entered into an agreement with GE Commercial Distribution Finance Corporation (CDF) to provide floor plan financing for certain dealer purchases of ShoreMaster products. Financings under this agreement began in 2008. As part of its marketing programs, ShoreMaster pays floor plan financing costs of its dealers for CDF financed purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. CDF exercised its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement has no effect on ShoreMaster s obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for expenses incurred by CDF before or after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement. The floor plan financing agreement requires ShoreMaster to repurchase new and unused inventory repossessed by CDF to satisfy the dealer s obligations to CDF under this agreement. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.8 million on March 31, 2009. ShoreMaster has incurred no losses under this agreement. We believe current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement.

Cash provided by operating activities was $21.9 million for the three months ended March 31, 2009 compared with cash provided by operating activities of $7.4 million for the three months ended March 31, 2008. The $14.5 million increase in cash from operating activities reflects a $3.1 million increase in operating cash flows related to changes in noncurrent liabilities and deferred credits and a $10.6 million decrease in cash used for working capital items from $18.5 million in the first quarter of 2008 to $7.9 million in the first quarter of 2009.

Major uses of funds for working capital items in the first three months of 2009 were a decrease in payables and other current liabilities of $33.4 million and a decrease in interest and income taxes payable/receivable of $6.9 million, offset by a decrease in receivables of $18.5 million, a decrease in other current assets of $9.9 million and a decrease in inventories of $4.1 million. The $33.4 million decrease in payables and other current liabilities includes: (1) $12.8 million related to the payment of accrued wages and benefits in the first quarter of 2009, (2) a $12.0 million reduction in accounts payable at DMI mainly related to steel purchases and (3) a $7.9 million reduction in accounts payable at the electric utility related to reductions in purchased power costs and a March 2009 interim rate refund credited to Minnesota customers. The $6.9 million decrease in interest and income taxes payable/receivable is mainly related to recent reductions in income tax expenses combined with the accrual of renewable energy tax credits earned in the first quarter of 2009. The $18.5 million decrease in accounts receivable reflects decreases in trade receivables in our nonelectric businesses due to declines in production, construction and sales activity related to the current economic recession, and collections of receivables outstanding on December 31, 2008. The $9.9 million decrease in other current assets includes: (1) a decrease of $11.0 million in costs in excess of billings at DMI as a result of decreased production activity and (2) a $7.1 million decrease in accrued utility revenues related to a decreases in unbilled and accrued fuel clause adjustment revenues due to seasonal kwh sales reductions and declining purchased power costs, offset by (3) a $7.8 million increase in prepaid expenses related to the payment of 2009 insurance premiums. The $4.1 million decrease in inventories includes a $4.4 million reduction in inventories at the plastic pipe companies related to reductions in production and sales.

Net cash used in investing activities was $28.8 million for the three months ended March 31, 2009 compared with $56.7 million for the three months ended March 31, 2008. Cash used for capital expenditures decreased by $30.9 million between the quarters mainly due to a $28.2 million decrease in capital expenditures at the electric utility related to first quarter 2008 payments for the construction of wind turbines at the Langdon Wind Energy Center. The increase in other investments reflects the purchase of $2.5 million of investments by our captive insurance company.
Net cash provided by financing activities was $2.2 million for the three months ended March 31, 2009 compared with $18.7 million for the three months ended March 31, 2008. Proceeds from short-term borrowings of $14.1 million in the first quarter of 2009 used to fund a portion of capital expenditures compared to proceeds from short-term borrowings of

$27.2 million in the first quarter of 2008. The Company paid $10.7 million in dividends on common and preferred shares in the first quarter of 2009 compared with $9.1 million in the first quarter of 2008. The increase in dividend payments is due to an 18.3% increase in common shares outstanding between the quarters mainly related to our September 2008 common stock offering. There were no proceeds from the issuance of long-term debt in the first quarter of 2009 compared with $1.1 million in the first quarter of 2008.

Our purchase obligations in our contractual obligations table reported under the caption Capital Requirements on page 27 of our 2008 Annual Report to Shareholders have increased by $3.0 million for 2009 and $6.5 million for 2010 related to an agreement entered into in March 2009 for the purchase of coal to cover a portion of current coal requirements at the electric utility s Big Stone Plant.

We do not have any off-balance-sheet arrangements or any material relationships with unconsolidated entities or financial partnerships.

Critical Accounting Policies Involving Significant Estimates

The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption Critical Accounting Policies Involving Significant Estimates on pages 34 through 36 of our 2008 Annual Report to Shareholders. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2009.

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Forward Looking Information Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as may , will , expect , anticipate , continue , estimate , project , believes or sim are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act.

The following factors, among others, could cause actual results for the Company to differ materially from those discussed in the forward-looking statements:

- We are subject to federal and state legislation, regulations and actions that may have a negative impact on our business and results of operations.
- Federal and state environmental regulation could cause us to incur substantial capital expenditures and increased operating costs.
- Volatile financial markets and changes in our debt rating could restrict our ability to access capital and could increase borrowing costs and pension plan expenses. Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of customers to finance purchases of goods and services, and our financial condition as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.
- Our defined benefit pension plan assets declined significantly during 2008 due to the volatile equity markets. We are not required to make a mandatory contribution to the pension plan in 2009. However, if the market value of pension plan assets continues to decline and relief under the Pension Protection Act is no longer granted, we could be required to contribute additional capital to the pension plan in 2010.
- A sustained decline in our common stock price below book value may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as credit facility covenants.
- Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net operating performance.
- Economic conditions could negatively impact our businesses.
- If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.
- Our plans to grow and diversify through acquisitions and capital projects may not be successful and could result in poor financial performance.
- Our plans to acquire additional businesses and grow and operate our nonelectric businesses could be limited by state law.
- The terms of some of our contracts could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.
- We are subject to risks associated with energy markets.
- Certain of our operating companies sell products to consumers that could be subject to recall.
- Competition is a factor in all of our businesses.
- We may experience fluctuations in revenues and expenses related to our electric operations, which may cause financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations.
- Our electric segment has capitalized $11.9 million in costs related to the planned construction of a second electric generating unit at the Big Stone Plant site as of March 31, 2009. If the project is abandoned for permitting or other reasons, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

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Actions by the regulators of our electric segment could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

Future operating results of our electric segment will be impacted by the outcome of rate rider filings in Minnesota for transmission investments.

Future operating results of our electric segment will be impacted by the outcome of a rate case filed in North Dakota on November 1, 2008 requesting an overall increase in North Dakota rates of 5.14%. The filing included a request for an interim rate increase of 4.07%, which went into effect on January 1, 2009. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes a final determination on the electric utility s request, which is expected by August 1, 2009. If final rates are lower than interim rates, the electric utility will refund North Dakota customers the difference with interest.

We may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Wholesale sales of electricity from excess generation could be affected by reductions in coal shipments to the Big Stone and Hoot Lake plants due to supply constraints or rail transportation problems beyond our control.

Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in carbon dioxide (CO2) emission levels, taxes on CO2 emissions or cap and trade regimes, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

Our plastics segment is highly dependent on a limited number of vendors for PVC resin, many of which are located in the Gulf Coast regions, and a limited supply of resin. The loss of a key vendor or an interruption or delay in the supply of PVC resin could result in reduced sales or increased costs for this business. Reductions in PVC resin prices could negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

Our plastic pipe companies compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish the pipe companies products from those of its competitors.

Competition from foreign and domestic manufacturers, the price and availability of raw materials, fluctuations in foreign currency exchange rates and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

Changes in the rates or method of third-party reimbursements for diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease revenues and earnings for our health services segment.

Our health services businesses may be unable to continue to maintain agreements with Philips Medical from which the businesses derive significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade their equipment.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.

Our food ingredient processing segment operates in a highly competitive market and is dependent on adequate sources of raw materials for processing. Should the supply of these raw materials be affected by poor growing conditions, this could negatively impact the results of operations for this segment.

Our food ingredient processing business could be adversely affected by changes in foreign currency exchange rates.

A significant failure or an inability to properly bid or perform on projects by our construction businesses could lead to adverse financial results.

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