Otter Tail Corp
Form 10-Q
August 07, 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 June 30, 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 0-53713

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota	27-0383995
(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 a 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:

July 31, 2009 35,611,789 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-

	June 30, 2009	December 31, 2008
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 9,056	$ 7,565
Accounts Receivable:		
Trade Net	107,239	136,609
Other	9,757	13,587
Inventories	92,140	101,955
Deferred Income Taxes	8,402	8,386
Accrued Utility and Cost-of-Energy Revenues	11,952	24,030
Costs and Estimated Earnings in Excess of Billings	50,605	65,606
Income Taxes Receivable	11,955	26,754
Other	20,225	8,519
Total Current Assets	321,331	393,011
Investments	8,634	7,542
Other Assets	88,249	22,615
Goodwill	106,778	106,778
Other Intangibles Net	34,637	35,441
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	9,598	7,247
Regulatory Assets and Other Deferred Debits	81,336	82,384
Total Deferred Debits	90,934	89,631
Plant		
Electric Plant in Service	1,210,035	1,205,647
Nonelectric Operations	343,358	321,032
Total Plant	1,553,393	1,526,679
Less Accumulated Depreciation and Amortization	575,448	548,070
Plant Net of Accumulated Depreciation and Amortization	977,945	978,609
Construction Work in Progress	82,230	58,960
Net Plant	1,060,175	1,037,569

Total	$ 1,710,738	$ 1,692,587

See accompanying notes to consolidated financial statements

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

	June 30, 2009	December 31, 2008
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 119,914	$ 134,914
Current Maturities of Long-Term Debt	1,242	3,747
Accounts Payable	85,927	113,422
Accrued Salaries and Wages	19,437	29,688
Accrued Taxes	8,155	10,939
Other Accrued Liabilities	13,240	12,034
Total Current Liabilities	247,915	304,744
Pensions Benefit Liability	82,882	80,912
Other Postretirement Benefits Liability	33,464	32,621
Other Noncurrent Liabilities	20,095	19,391
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	132,923	123,086
Deferred Tax Credits	33,212	34,288
Regulatory Liabilities	65,801	64,684
Other	427	397
Total Deferred Credits	232,363	222,455
Capitalization		
Long-Term Debt, Net of Current Maturities	411,835	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 35,558,465 and 2008 35,384,620	177,792	176,923
Premium on Common Shares	243,933	241,731
Retained Earnings	246,025	260,364

Accumulated Other Comprehensive Loss	(2,286)	(3,000)
Total Common Equity	665,464	676,018
Total Capitalization	1,094,019	1,032,464
Total	$ 1,710,738	$ 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 June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating Revenues				
Electric	$ 70,610	$ 68,577	$ 159,089	$ 166,083
Nonelectric	176,247	255,023	365,007	457,754
Total Operating Revenues	246,857	323,600	524,096	623,837
Operating Expenses				
Production Fuel Electric	11,754	14,808	30,413	34,712
Purchased Power Electric System Use	11,877	10,156	29,250	29,142
Electric Operation and Maintenance Expenses	28,959	27,757	55,889	54,500
Cost of Goods Sold Nonelectric (depreciation included below)	135,319	204,235	288,280	369,458
Other Nonelectric Expenses	32,410	36,242	63,044	70,989
Product Recall and Testing Costs			1,766	
Plant Closure Costs		1,412		1,412
Depreciation and Amortization	18,103	16,124	35,920	31,037
Property Taxes Electric	2,255	2,563	4,745	5,187
Total Operating Expenses	240,677	313,297	509,307	596,437
Operating Income	6,180	10,303	14,789	27,400
Other Income	1,351	626	2,018	1,588
Interest Charges	6,652	7,043	12,922	13,754
Income Before Income Taxes	879	3,886	3,885	15,234
Income Taxes	(1,852)	369	(3,234)	3,487
Net Income	2,731	3,517	7,119	11,747
Preferred Dividend Requirements	184	184	368	368
Earnings Available for Common Shares	$ 2,547	$ 3,333	$ 6,751	$ 11,379
Earnings Per Common Share:				
Basic	$ 0.07	$ 0.11	$ 0.19	$ 0.38
Diluted	$ 0.07	$ 0.11	$ 0.19	$ 0.38

Average Number of Common Shares Outstanding:				
Basic	35,388,754	29,993,484	35,356,745	29,905,782
Diluted	35,643,707	30,300,207	35,610,545	30,198,967
Dividends Per Common Share	$ 0.2975	$ 0.2975	$ 0.5950	$ 0.5950

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 7,119	$ 11,747
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	35,920	31,037
Deferred Tax Credits	(1,075)	(782)
Deferred Income Taxes	9,614	5,959
Change in Deferred Debits and Other Assets	(538)	(2,627)
Change in Noncurrent Liabilities and Deferred Credits	3,826	752
Allowance for Equity (Other) Funds Used During Construction	(1,003)	(801)
Change in Derivatives Net of Regulatory Deferral	(661)	(655)
Stock Compensation Expense	1,754	1,908
Other Net	139	316
Cash Provided by (Used for) Current Assets and Current Liabilities:		
Change in Receivables	33,264	(1,904)
Change in Inventories	10,130	(10,082)
Change in Other Current Assets	18,688	(17,520)
Change in Payables and Other Current Liabilities	(41,161)	16,244
Change in Interest and Income Taxes Payable/Receivable	14,289	1,348
Net Cash Provided by Operating Activities	90,305	34,940
Cash Flows from Investing Activities		
Capital Expenditures	(57,930)	(117,785)
Proceeds from Disposal of Noncurrent Assets	4,551	3,517
Acquisitions Net of Cash Acquired		(41,674)
Net (Increase) Decrease in Other Investments and Long-Term Assets	(66,671)	(376)
Net Cash Used in Investing Activities	(120,050)	(156,318)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash		3,636
Net Short-Term Borrowings	(15,000)	91,600
Proceeds from Issuance of Common Stock	1,901	5,176
Common Stock Issuance Expenses	(17)	
Payments for Retirement of Common Stock	(229)	(91)
Proceeds from Issuance of Long-Term Debt	75,004	1,137
Short-Term and Long-Term Debt Issuance Expenses	(3,175)	(19)
Payments for Retirement of Long-Term Debt	(5,438)	(1,829)
Dividends Paid	(21,457)	(18,212)

Net Cash Provided by Financing Activities		31,589		81,398
Effect of Foreign Exchange Rate Fluctuations on Cash		(353)		156
Net Change in Cash and Cash Equivalents		1,491		(39,824)
Cash and Cash Equivalents at Beginning of Period		7,565		39,824
Cash and Cash Equivalents at End of Period	$	9,056	$	

See accompanying notes to consolidated financial statements

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

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby Otter Tail Power Company, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (formerly known as Otter Tail Holding Company). See Note 19 Subsequent Events. The new parent holding company (now known as Otter Tail Corporation) was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. References in this report to Otter Tail Corporation and the Company refer, for periods prior to July 1, 2009, to the corporation that was the registrant prior to the reorganization, and, for periods after the reorganization, to the new parent holding company, in each case including its consolidated subsidiaries, unless otherwise indicated or the context otherwise requires.

In the opinion of management, 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-month and six-month periods ended June 30, 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 25.7% for the three months ended June 30, 2009 compared with 33.6% for the three months ended June 30, 2008 and 27.6% for the six months ended June 30, 2009 compared with 31.0% for the six months ended June 30, 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.

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

(in thousands)	June 30, 2009	December 31, 2008
Costs Incurred on Uncompleted Contracts	$ 374,103	$ 377,237
Less Billings to Date	(380,992)	(366,931)
Plus Estimated Earnings Recognized	53,686	47,355
	$ 46,797	$ 57,661

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)	June 30, 2009	December 31, 2008
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$50,605	$65,606
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(3,808)	(7,945)
	$46,797	$57,661

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $43,894,000 as of June 30, 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 $8,356,000 on June 30, 2009 and $10,311,000 on December 31, 2008.

Sales of Receivables

DMI has a $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $64.8 million have been sold in 2009. Discounts and commissions and fees of $92,000 for the three months ended June 30, 2009 and $267,000 for the six months ended June 30, 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 charged to revenue were

$88,000 for the three months ended June 30, 2009 and $233,000 for the six months ended June 30, 2009 compared with $240,000 for both the three and six months ended June 30, 2008.

Supplemental Disclosures of Cash Flow Information

	Six Months Ended June 30,	
(in thousands)	2009	2008
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$330	$(21,419)

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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 June 30, 2009:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market, Mutual Funds and Cash	$ 782	$	$	$ 782
Cash Surrender Value of Life Insurance Policies		8,598		8,598
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,941		10,941
Forward Energy Contracts		3,595		3,595
Forward Foreign Currency Exchange Contracts	120			120
Investments of Captive Insurance Company:				
Corporate Debt Securities	4,112			4,112
U.S. Government Debt Securities	1,930			1,930
Total Assets	$6,944	$23,134	$	$30,078
Liabilities:				
Forward Energy Contracts	$	$ 3,727	$	$ 3,727
Forward Foreign Currency Exchange Contracts	41			41
Asset Retirement Obligations			3,438	3,438
Total Liabilities	$ 41	$ 3,727	$ 3,438	$ 7,206
Net Assets (Liabilities)	$6,903	$19,407	$(3,438)	$22,872

Inventories

Inventories consist of the following:

(in thousands)	June 30, 2009	December 31, 2008
Finished Goods	$39,946	$ 38,943
Work in Process	6,674	10,205
Raw Material, Fuel and Supplies	45,520	52,807
Total Inventories	$92,140	$101,955

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Other Intangible Assets

The following table summarizes the components of the Company s intangible assets at June 30, 2009 and December 31, 2008:

June 30, 2009 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,190	$ 1,938	$ 252	3 - 5 years
Customer Relationships	26,884	3,059	23,825	15 - 25 years
Other Intangible Assets Including Contracts	2,359	1,670	689	5 - 30 years
Total	$ 31,433	$ 6,667	$ 24,766	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,871	$	$ 9,871	
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 $835,000 for the six months ended June 30, 2009 compared to $563,000 for the six months ended June 30, 2008. The estimated annual amortization expense for these intangible assets for the next five years is $1,639,000 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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2009	2008	2009	2008

Net Income	$2,731	$3,517	$7,119	$11,747
Other Comprehensive Gain (Loss) (net-of-tax):				
Foreign Currency Translation Gain (Loss)	1,008	77	584	(375)
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	89	37	104	80
Unrealized Gain (Loss) on Available-for-Sale Securities	81	(94)	26	(35)
Total Other Comprehensive Gain (Loss)	1,178	20	714	(330)
Total Comprehensive Income	$3,909	$3,537	$7,833	$11,417

New Accounting Standards

SFAS No. 141 (revised 2007), ***Business Combinations (SFAS No. 141(R)),*** was issued by the Financial Accounting Standards Board (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.

FASB Staff Position (FSP) FAS 107-1 and Accounting Principles Board (APB) 28-1), ***Interim Disclosures about Fair Value of Financial Instruments,*** was issued by the FASB in April 2009. FSP FAS 107-1 and APB 28-1, amends SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*, and APB Opinion No. 28, *Interim Financial Reporting*, to require disclosures regarding the fair value of financial instruments in interim financial statements. FSP FAS 107-1 and APB 28-1 was effective for interim periods ending after June 15, 2009. The Company implemented FSP FAS 107-1 and APB 28-1 on April 1, 2009. The implementation did not have a material impact on the Company s consolidated financial statements. FSP FAS 107-1 and APB 28-1 required disclosures have been included in the Company s notes to consolidated financial statements, where applicable.

SFAS No. 165, ***Subsequent Events*****,** was issued by the FASB in May 2009. SFAS No. 165 establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The accounting guidance contained in SFAS No. 165 is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, SFAS No. 165 requires an entity to disclose the date through which subsequent events have been evaluated. SFAS No. 165 is effective for interim and annual periods ending after June 15, 2009. The Company implemented SFAS No. 165 on April 1, 2009. The implementation did not have a material impact on the Company s consolidated financial statements.

SFAS No. 167, ***Amendments to FASB Interpretation No. 46(R),*** was issued by the FASB in June 2009. SFAS No. 167 amends the consolidation guidance applicable to variable interest entities. The amendments will significantly affect various elements of consolidation guidance under FASB Interpretation No. 46(R), including guidance for determining whether an entity is a variable interest entity and whether an enterprise is the primary beneficiary of a variable interest entity. SFAS No. 167 is effective for fiscal years beginning after Nov. 15, 2009. The Company does not expect the implementation of SFAS No. 167 to have a significant impact on its consolidated financial statements.

SFAS No. 168, ***The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162*****,** was issued by the FASB in June 2009. SFAS No. 168 confirms that the FASB Accounting Standards Codification (Codification) is the single source of authoritative GAAP, other than guidance put forth by the Securities and Exchange Commission. All other accounting literature not included in the Codification will be considered non-authoritative. SFAS No. 168 is effective for interim and annual periods ending after Sept. 15, 2009. The Company expects the implementation of SFAS No. 168 to have no impact on its consolidated financial statements. However, all references to accounting standards in future filings will be to applicable standards in the Codification or to applicable code sections within the Codification.

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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 1907.

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 four Canadian provinces.

Our electric operations, including wholesale power sales, are operated by our wholly owned subsidiary, Otter Tail Power Company, and our energy services operation is operated by a separate wholly owned 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.

No single external customer accounted for 10% or more of the Company s revenues in the six months ended June 30, 2009. 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
United States of America	97.3%	97.2%	97.9%	96.6%
Canada	1.3%	1.5%	1.0%	1.4%
All Other Countries (none greater than 1%)	1.4%	1.3%	1.1%	2.0%

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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 and six month periods ended June 30, 2009 and 2008 and total assets by business segment as of June 30, 2009 and December 31, 2008 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2009	2008	2009	2008
Electric	$ 70,663	$ 68,666	$159,204	$166,256
Plastics	22,183	40,645	35,713	62,995
Manufacturing	76,843	120,342	172,862	217,937
Health Services	28,192	30,740	56,359	60,005
Food Ingredient Processing	20,581	15,913	40,667	31,811
Other Business Operations	29,597	48,080	61,492	86,190
Corporate Revenues and Intersegment Eliminations	(1,202)	(786)	(2,201)	(1,357)
Total	$246,857	$323,600	$524,096	$623,837

Interest Expense

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2009	2008	2009	2008
Electric	$4,266	$3,133	$ 8,277	$ 6,114
Plastics	199	327	399	468
Manufacturing	1,439	2,231	2,718	4,377
Health Services	100	176	196	355
Food Ingredient Processing	10	31	20	41
Other Business Operations	112	295	232	602
Corporate and Intersegment Eliminations	526	850	1,080	1,797
Total	$6,652	$7,043	$12,922	$13,754

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2009	2008	2009	2008
Electric	$ (832)	$ (266)	$ 939	$ 6,154
Plastics	198	429	(1,449)	854
Manufacturing	(208)	618	(1,012)	15
Health Services	(63)	(11)	(76)	(426)
Food Ingredient Processing	1,613	614	2,338	1,214
Other Business Operations	(944)	543	(1,150)	(617)

Corporate	(1,616)	(1,558)	(2,824)	(3,707)
Total	$(1,852)	$ 369	$(3,234)	$ 3,487

Earnings Available for Common Shares

(in thousands)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Electric	$ 4,211	$ 3,092	$12,553	$15,658
Plastics	291	652	(2,167)	1,272
Manufacturing	(167)	1,396	(1,257)	780
Health Services	(153)	(88)	(226)	(779)
Food Ingredient Processing	2,325	685	3,772	1,808
Other Business Operations	(1,456)	794	(1,781)	(971)
Corporate	(2,504)	(3,198)	(4,143)	(6,389)
Total	$ 2,547	$ 3,333	$ 6,751	$11,379

Total Assets

(in thousands)	June 30, 2009	December 31, 2008
Electric	$1,059,063	$ 992,159
Plastics	74,239	78,054
Manufacturing	313,719	356,697
Health Services	59,843	61,086
Food Ingredient Processing	87,426	88,813
Other Business Operations	62,785	71,359
Corporate	53,663	44,419
Total	$1,710,738	$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.

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. The MPUC did take up reconsideration of the original order regarding the conditions.

Upon deliberation, the MPUC slightly modified the conditions on the Brookings line. 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 2010 and 2011), construction will begin. The lines would be expected to be completed over a two to four year period. 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 (CON) 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 MNOES subsequently recommended a determination that need for the line has been established. The Environmental Report for the CON was issued in April 2009. CON hearings were conducted on May 20 and May 21, 2009 and a summary of comments was issued on June 8, 2009. The CON was placed on the MPUC agenda for July 9, 2009. The MNOES and the National Forest Service continue to work on the Environmental Impact Statement (EIS) for the project. The MNOES expects to issue a draft EIS by September 1, 2009. The MNOES further expects to have the hearings for the Bemidji-Grand Rapids route in November 2009. The MPUC is expected to determine if there is a need for this line and, if appropriate, issue the route permit in summer 2010.

<u>Renewable Energy Standards, Conservation, Renewable Resource and Transmission Riders</u> 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 (RRA) 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 s 2009 RRA 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 MPUC acted on the electric utility s petition for a 2009 RRA in July 2009 approving an RRA of 0.415 cents per kwh for the recovery of $6.6 million through March 31, 2010 $4.0 million from August through December 2009 and $2.6 million from January through March 2010 and for accrued renewable resource recovery revenues not recovered through billings by March 31, 2010, recovery was granted over a 48-month period beginning in April 2010. The electric utility has recognized a regulatory asset of $4.8 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of June 30, 2009.

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. Additionally, following approval of the tariff, the MPUC may approve annual rate adjustments filed pursuant to the tariff. The electric utility filed a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrade projects on July 28, 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. The North Dakota Public Service Commission s (NDPSC) order authorizing an interim rate increase requires the electric utility to refund North Dakota customers the difference between final and interim rates, with interest, if final rates approved by the NDPSC are lower than interim rates. NDPSC advocacy staff and intervenors testimony was received in April 2009. A tentative settlement of all issues in the case, joined by all parties and NDPSC advocacy staff, was filed with the NDPSC in June 2009. The NDPSC scheduled a September 28, 2009 hearing for the purpose of considering the settlement. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes its final determination. In June 2009, based on terms agreed to in the tentative settlement, the electric utility established a refund reserve of $0.5 million for revenues collected under interim rates.

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, which reflects cost recovery for the electric utility s 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 General 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 a settlement of all issues, including all issues relative to Renewable Resource Cost Recovery Rider, will be considered by the NDPSC at a September 28, 2009 hearing. The proposed settlement reflects some changes in the timing of cost recovery and a reduction in the RRA. The electric utility will apply for a Renewable Resource Cost Recovery Rider Adjustment to be effective January 1, 2010, to include cost recovery for its Luverne Wind Project.

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 June 30, 2009 consolidated balance sheet includes a regulatory asset of $1.2 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 June 30, 2009.

Terms of the proposed settlement provide for the recovery of accrued but unbilled North Dakota resource recovery rider revenues over a period of 48 months beginning in January 2010.

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 electric utility increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed by South Dakota statutes. In an order issued by the South Dakota Public Utilities Commission on June 30, 2009 the electric utility was granted an increase in South Dakota retail electric rates of $2.9 million or approximately 11.7%. The electric utility implemented final, approved rates in July 2009.

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).

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. 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.

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On June 12, 2009 the FERC issued an order on rehearing of the November 10, 2008 order. The order on rehearing, at a minimum, relieved MISO from having to resettle RSG payments resulting from any difference between the megawatt-hours associated with virtual supply in the denominator of the RSG rate and the billing determinants associated with virtual supply transactions (VSO mismatch). This relief applies to the period April 25, 2006 through November 4, 2007. Since the electric utility would have had a payment obligation associated with the virtual supply and other mismatches, the June order eliminates that payment obligation. However, the June order, like many of the other orders in this docket, is subject to appellate review and potential reversal. Beginning November 5, 2007, MISO is obligated to resettle to correct the VSO mismatch, which may impose a payment obligation on the electric utility. Whether other mismatches must be resettled will not be determined until the FERC issues orders addressing the December 2008 compliance filings. The Company does not know when these litigation proceedings will conclude.

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 were the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement, which expired on January 1, 2009 pursuant to a provision in the 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 were 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, was an additional party to the Joint Facilities Agreement.

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.

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 intervenors filed an appeal of the Certificate of Need with the Minnesota Court of Appeals in early June 2009. The intervenors, applicants and the MPUC filed briefs in July and early August 2009.

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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. On June 2, 2009 the MPUC issued an order denying reconsideration. 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 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 appealed the administrative decision on the PSD permit to the Circuit Court of Hughes County. In July 2009, the parties entered into a stipulation dismissing the appeal with prejudice. 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 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 the EPA did not object within its review period. The EPA did not file any comments or objections and the South Dakota Department of Environment and Natural Resources issued the permit on June 9, 2009. On August 3, 2009 the Sierra Club and Clean Water Action petitioned the EPA to object to the Title V permit.

The Big Stone II federal EIS process led by the Western Area Power Administration (WAPA) continues to move forward. WAPA and its third party subcontractor completed the Final EIS, which included comments on the Draft EIS and the Supplemental Draft EIS, and responses to those comments. Notice of Availability of the EIS was published in the Federal Register on June 26, 2009. WAPA can issue a final Record of Decision (ROD) at the conclusion of a 30-day waiting period following publication of the NOA, which ended on July 27, 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 had 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 June 30, 2009 the electric utility has capitalized $12.8 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)	June 30, 2009	December 31, 2008
Regulatory Assets:		
Unrecognized Prior Service Costs and Actuarial Losses on Pension Benefits	$63,868	$64,490
Deferred Income Taxes	6,392	7,094
Minnesota Renewable Resource Rider Accrued Revenues	4,846	3,045
Debt Reacquisition Premiums	3,191	3,357
Accumulated ARO Accretion/Depreciation Adjustment	1,596	1,437
Minnesota General Rate Case Recoverable Expenses	1,472	1,457
North Dakota Renewable Resource Rider Accrued Revenues	1,165	2,009
Accrued Cost-of-Energy Revenue	736	8,982
MISO Schedule 16 and 17 Deferred Administrative Costs ND	686	823
Deferred Marked-to-Market Losses	629	1,162
MISO Schedule 16 and 17 Deferred Administrative Costs MN	389	526
Deferred Holding Company Formation Costs	180	
Plant Acquisition Costs	41	63
Deferred Conservation Improvement Program Costs	(95)	280
Total Regulatory Assets	$85,096	$94,725
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$59,654	$58,768
Deferred Income Taxes	4,602	4,943
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	1,082	834
Deferred Marked-to-Market Gains	326	
Gain on Sale of Division Office Building	137	139
Total Regulatory Liabilities	$65,801	$64,684
Net Regulatory Asset Position	$19,295	$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*.
Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of June 30, 2009. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 57 months, from July 2009 through March 2014.
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 23.3 years.

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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 31 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 that have not been billed to North Dakota customers as of June 30, 2009. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 54 months, from July 2009 through January 2014.
Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 14 months.
MISO Schedule 16 and 17 Deferred Administrative Costs ND will be recovered over the next 30 months.
All Deferred Marked-to-Market Gains and Losses recorded as of June 30, 2009 are related to forward purchases of energy scheduled for delivery through April 2013.
MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 17 months.
Deferred Holding Company Formation Costs will be amortized over the next 5 years.
Plant Acquisition Costs will be amortized over the next 11 months.
Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 12 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 June 30, 2009 the electric utility had recognized, on a pretax basis, $171,000 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

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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.

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 June 30, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to June 30, 2009:

(in thousands)	June 30, 2009	December 31, 2008
In Other Current Assets Marked-to-Market Gain	$ 3,595	$ 405
In Regulatory Assets and Other Deferred Debits Deferred Marked-to-Market Loss	629	1,162
In Other Accrued Current Liabilities - Marked-to-Market Loss	(3,727)	(1,690)
In Regulatory Liabilities Deferred Marked-to-Market Gain	(326)	
Net Fair Value of Marked-to-Market Energy Contracts	$ 171	$ (123)

(in thousands)	Year-to-Date June 30, 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	171
Net Fair Value End of Period	$ 171

Realized and unrealized net gains (losses) on forward energy contracts of $140,000 for the three months ended June 30, 2009, $1,174,000 for the six months ended June 30, 2009, ($31,000) for the three months ended June 30, 2008 and $2,219,000 for the six months ended June 30, 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 June 30, 2009 was $2,156,000. As of June 30, 2009 the net credit risk exposure was $5,965,000 from ten counterparties with investment grade credit ratings and two 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 June 30, 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 $5,965,000 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 June 30, 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 $3,727,000 derivative liability on June 30, 2009 are covered by deposited funds. The aggregate fair value of these derivative liabilities on June 30, 2009 was $1,472,000. 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 Company had no forward energy derivative contracts with credit-risk-related contingent features in a liability position on June 30, 2009.

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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 No. 133, as amended by SFAS No. 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 June 30, 2009:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in July 2008	July 2009	$ 400	$ 417
Contracts entered into in October 2008	July 2009 October 2009	1,600	1,999
Contracts outstanding on June 30, 2009	July 2009 October 2009	$2,000	$2,416

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 June 30, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to June 30, 2009:

(in thousands)	June 30, 2009	December 31, 2008
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:		
Other Current Assets	$ 120	$
Other Accrued Current Liabilities	(42)	(289)
Net Fair Value of Foreign Currency Exchange Forward Windows	$ 78	$ (289)

(in thousands)	Year-to-Date June 30, 2009
Fair Value at Beginning of Year	$ (289)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	277
Changes in Fair Value of Contracts Entered into in 2008	90
Net Fair Value of Contracts Entered into in 2008 at End of Period	78
Changes in Fair Value of Contracts Entered into in 2009	

Net Fair Value End of Period	$ 78

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 June 30, 2009 were valued and marked to market on June 30, 2009 based on quoted exchange values on June 30, 2009. Realized and unrealized net gains on IPH s foreign currency exchange forward windows of $234,000 for the three months ended June 30, 2009 and $90,000 for the six months ended June 30, 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.

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6. Common Shares and Earnings Per Share

Following is a reconciliation of the Company s common shares outstanding from December 31, 2008 through June 30, 2009:

Common Shares Outstanding, December 31, 2008	35,384,620
Issuances:	
Dividend Reinvestment Plan Dividend Purchases	59,538
Executive Officer Stock Performance Awards	29,350
Restricted Stock Issued to Nonemployee Directors	28,800
Restricted Stock Issued to Employees	27,600
Dividend Reinvestment Plan Direct Purchases	26,181
Employee Stock Purchase Plan Dividend Reinvestment	5,859
Vesting of Restricted Stock Units	5,350
Stock Options Exercised	1,350
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(10,183)
Common Shares Outstanding, June 30, 2009	35,558,465

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 three-month and six-month periods ended June 30, 2009 and 2008:

Three Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2009	419,460	$24.93 $31.34
2008		NA

Six Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2009	419,460	$24.93 $31.34
2008		NA

7. Share-Based Payments

The Company has five share-based payment programs.

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.

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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 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.

As of June 30, 2009 the remaining unrecognized compensation expense related to stock-based compensation was approximately $7.9 million (before income taxes) which will be amortized over a weighted-average period of 2.4 years.

Amounts of compensation expense recognized under the Company s five stock-based payment programs for the three-month and six-month periods ended June 30, 2009 and 2008 are presented in the table below:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2009	2008	2009	2008
Employee Stock Purchase Plan (15% discount)	$ 72	$ 65	$ 162	$ 135
Restricted Stock Granted to Directors	143	132	254	240
Restricted Stock Granted to Employees	111	121	202	239
Restricted Stock Units Granted to Employees	148	144	269	238
Stock Performance Awards Granted to Executive Officers	787	784	1,222	1,124
Totals	$1,261	$1,246	$2,109	$1,976

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 $3.9 million on June 30, 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 was denied on July 22, 2009. On July 31, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The ultimate outcome of this matter 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 43.5% as of the end of July 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 June 30, 2009 will not be material.

10. Short-Term and Long-Term Borrowings

Term Loan Agreement

On May 22, 2009, Otter Tail Corporation, d/b/a Otter Tail Power Company (now known as Otter Tail Power Company) entered into a Term Loan Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, KeyBank National Association, as syndication agent, Union Bank, N.A., as documentation agent, and the banks named therein. The Loan Agreement provides for a $75 million term loan to Otter Tail Power Company due May 20, 2011, which was fully drawn on May 22, 2009.

Borrowings under the Loan Agreement bear interest at a rate equal to the base rate in effect from time to time. The base rate is a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A. s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of Otter Tail Power Company s senior unsecured credit ratings, as provided in the Loan Agreement. At Otter Tail Power Company s option, the interest rate on outstanding borrowings may be converted to a LIBOR rate that would fluctuate based on the rate at which deposits of U.S. dollars in the London interbank market are quoted, plus a margin of 2.5% to 4.0% determined on the basis of Otter Tail Power Company s senior unsecured credit ratings, as provided in the Loan Agreement. Otter Tail Power Company is using the proceeds borrowed under the Loan Agreement to support its working capital needs and other capital requirements, including construction of the Luverne Wind Farm in North Dakota. The interest rate on borrowings under the Loan Agreement was 3.81% at June 30, 2009.

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The Loan Agreement contains a number of restrictions on the business of Otter Tail Power Company, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Loan Agreement also contains certain financial covenants. Specifically, Otter Tail Power Company must not permit the ratio of its Interest-bearing Debt to Total Capitalization (each as defined in the Loan Agreement) to be greater than 0.60 to 1.00, or permit its Interest and Dividend Coverage Ratio (as defined in the Loan Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The Loan Agreement also contains affirmative covenants and events of default. The Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in Otter Tail Power Company s credit ratings. The obligations of Otter Tail Power Company under the Term Loan Agreement are unsecured. Since completion of the Company s holding company formation on July 1, 2009, the Loan Agreement is an obligation of Otter Tail Power Company. See Note 19 - Subsequent Events.

Debt Retirement

In June 2009, the Company paid $3,493,000 to retire early its Lombard US Equipment Finance Note due October 2, 2010. No penalty was paid for early retirement of the note.

Amendments to Note Purchase Agreements

In connection with Otter Tail Corporation s holding company reorganization on July 1, 2009, amendments to the following note purchase agreements were entered into in order to obtain the consent of the related noteholders to the reorganization.

Fourth Amendment to 2001 Note Purchase Agreement

On June 30, 2009 Otter Tail Corporation (now known as Otter Tail Power Company) (Old Otter Tail) entered into a Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001 (the Fourth Amendment) with the holders of the 2001 Notes referred to below, amending the Note Purchase Agreement dated as of December 1, 2001 among Old Otter Tail and each of the purchasers named on Schedule A attached thereto, as amended (the 2001 Note Purchase Agreement). The 2001 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail, in a private placement transaction, of its $90,000,000 6.63% Senior Notes due December 1, 2011 (the 2001 Notes). The Fourth Amendment sets forth the terms and conditions of the 2001 Noteholders consent to the holding company reorganization and amends certain provisions of the 2001 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail s note purchase agreements. These amendments include changes to negative covenants in the 2001 Note Purchase Agreement regarding limitations on liens and contingent liabilities, and to events of default. As provided in the Fourth Amendment, the 2001 Note Purchase Agreement and the 2001 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization. In addition, the guaranties issued by certain subsidiaries of Old Otter Tail under the 2001 Note Purchase Agreement and the 2001 Notes were released on the effectiveness of the holding company reorganization.

Third Amendment to 2007 Note Purchase Agreement

On June 26, 2009 Old Otter Tail entered into a Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007 (the Third Amendment) with the holders of the 2007 Notes referred to below, amending the Note Purchase Agreement dated as of August 20, 2007 among Old Otter Tail and each of the purchasers party thereto, as amended (the 2007 Note Purchase Agreement). The 2007 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail of $155 million aggregate principal amount of Old Otter Tail s Senior Unsecured Notes in four series, in the designations and aggregate principal amounts set forth in the 2007 Note Purchase Agreement (the 2007 Notes). The Third Amendment sets forth the terms and conditions of the 2007 Noteholders consent to the holding company reorganization and also amends certain provisions of the 2007 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail s note purchase agreements. These amendments include changes to negative covenants in the 2007 Note Purchase Agreement regarding limitations on liens and subsidiary guarantees. As provided in the Third Amendment, the 2007 Note Purchase Agreement and the 2007 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization.

Amendment No. 2 to Cascade Note Purchase Agreement

On June 30, 2009 Old Otter Tail entered into an Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007 (Amendment No. 2) with Cascade Investment, L.L.C. (Cascade), amending the Note Purchase Agreement dated as of February 23, 2007 between Old Otter Tail and Cascade, as amended (the Cascade Note Purchase

Agreement). The Cascade Note Purchase Agreement relates to the issuance and sale by Old Otter Tail to Cascade, in a private placement transaction, of Old Otter Tail s $50,000,000 5.778% Senior Note due November 30, 2017 (the Cascade Note). Amendment No. 2 sets forth the terms and conditions of Cascade s consent to the assignment by Old Otter Tail of its rights and obligations in, to and under the Cascade Note Purchase Agreement and the Cascade Note to Otter Tail Holding Company, the new parent holding company of Old Otter Tail that is now known as Otter Tail Corporation (the Company), effective immediately prior to the effectiveness of the holding company reorganization. Amendment No. 2 also provides for Cascade s consent to the holding company reorganization, and amends certain provisions of the Cascade Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among the Company s note purchase agreements. These amendments include changes to negative covenants in the Cascade Note Purchase Agreement regarding limitations on liens, contingent liabilities and to events of default. In addition, Amendment No. 2 provides for an additional financial covenant applicable to the Company as of the effectiveness of the holding company reorganization. Specifically, the Company may not permit the aggregate principal amount of all debt of Otter Tail Power Company and its subsidiaries to exceed 60% of Otter Tail Consolidated Total Capitalization (as defined in the Cascade Note Purchase Agreement, as amended by Amendment No. 2), determined as of the end of each fiscal quarter of the Company. In addition, the interest rate applicable to the Cascade Note was increased to 8.89% per annum which is reflective of the Company s new senior unsecured debt ratings. The obligations of the Company under the Cascade Note Purchase Agreement and the Cascade Notes continue to be guaranteed by Varistar Corporation and certain of its subsidiaries. As provided in Amendment No. 2, the Cascade Note Purchase Agreement and the Cascade Notes became obligations of the Company immediately prior to the effectiveness of the holding company reorganization.

Financial Covenants

Following the Company s holding company reorganization on July 1, 2009 the Company s borrowing agreements are subject to certain financial covenants. Specifically:

Under the credit agreement relating to the $200 million credit facility of the Company (as assignee of Varistar Corporation), the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the credit agreement.

Under the Cascade Note Purchase Agreement, the Company may not permit its Consolidated Debt to exceed 60% of Consolidated Total Capitalization or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the Debt of Otter Tail Power Company to exceed 60% of Otter Power Consolidated Total Capitalization, or permit the Priority Debt of Varistar and its subsidiaries to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.

Under the Loan Agreement and the credit agreement relating to Otter Tail Power Company s $170 million credit facility, Otter Tail Power Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.

Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, Otter Tail Power Company may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, Otter Tail Power Company may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

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11. Class B Stock Options of Subsidiary

As of June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$ 1,133	$ 1,275	$ 2,266	$ 2,550
Interest Cost on Projected Benefit Obligation	2,975	2,800	5,950	5,600
Expected Return on Assets	(3,448)	(3,550)	(6,896)	(7,100)
Amortization of Prior-Service Cost	181	175	362	350
Amortization of Net Actuarial Loss	5	125	10	250
Net Periodic Pension Cost	$ 846	$ 825	$ 1,692	$ 1,650

The Company did not make a contribution to its pension plan in the six months ended June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$188	$173	$ 376	$ 346
Interest Cost on Projected Benefit Obligation	424	384	848	768
Amortization of Prior-Service Cost	18	16	36	32
Amortization of Net Actuarial Loss	96	120	192	240
Net Periodic Pension Cost	$726	$693	$1,452	$1,386

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 June 30,		Six Months Ended June 30,	
(in thousands)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$ 301	$ 300	$ 602	$ 600
Interest Cost on Projected Benefit Obligation	753	725	1,506	1,450
Amortization of Transition Obligation	187	187	374	374
Amortization of Prior-Service Cost	53	50	106	100
Amortization of Net Actuarial Loss	1	125	2	250
Effect of Medicare Part D Expected Subsidy	(297)	(400)	(594)	(800)

Net Periodic Postretirement Benefit Cost	$ 998	$ 987	$1,996	$1,974

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15. Income Taxes

The Company s effective income tax rate for the three months ended June 30, 2009 was lower than the effective tax rate for the three months ended June 30, 2008. 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 $1.8 million in the second quarter of 2009 and $0.9 million in the second quarter of 2008.

The Company s effective income tax rate for the six months ended June 30, 2009 was lower than the effective tax rate for the six months ended June 30, 2008. The reduction from the federal statutory rate mainly reflects the benefit of PTCs and North Dakota wind energy credits related to the electric utility s wind projects of approximately $3.9 million in the first six months of 2009 and $1.5 million in the first six months 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 July 1, 2009 Otter Tail Corporation completed a holding company reorganization in accordance with Section 302A.626 of the Minnesota Business Corporation Act (the MBCA) whereby Otter Tail Power Company (also referred to as Old Otter Tail), which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (formerly known as Otter Tail Holding Company).

The new holding company structure was effected as of 12:00 a.m. Central Time on July 1, 2009 pursuant to a Plan of Merger dated as of June 30, 2009 (the Plan of Merger), by and among Old Otter Tail, Otter Tail Holding Company (now known as Otter Tail Corporation), a Minnesota corporation and, prior to the reorganization a direct subsidiary of Old Otter Tail, and Otter Tail Merger Sub Inc., a Minnesota corporation and indirect subsidiary of Old Otter Tail and direct subsidiary of Otter Tail Holding Company (Merger Sub). The Plan of Merger provided for the merger (the Merger) of Old Otter Tail with Merger Sub, with Old Otter Tail as the surviving corporation. Pursuant to Section 302A.626 (subd. 2) of the MBCA shareholder approval was not required for the Merger. As a result of the Merger, Old Otter Tail is now a wholly owned subsidiary of the Company with the name Otter Tail Power Company. Immediately following the completion of the Merger, the Company changed its name from Otter Tail Holding Company to Otter Tail Corporation.

In the Merger, each issued and outstanding common share of Old Otter Tail was converted into one common share of the Company, par value $5 per share, and each issued and outstanding cumulative preferred share of Old Otter Tail was converted into one cumulative preferred share of the Company having the same designations, rights, powers and preferences. In connection with the Merger, each person that held rights to purchase, or other rights to or interests in, common shares of Old Otter Tail under any stock option, stock purchase or compensation plan or arrangement of Old Otter Tail immediately prior to the Merger holds a corresponding number of rights to purchase, and other rights to or interests in, common shares of the Company, par value $5 per share, immediately following the Merger.

The conversion of the common shares in the Merger occurred without an exchange of certificates. Accordingly, certificates formerly representing outstanding common shares of Old Otter Tail are deemed to represent the same number of common shares of the Company.

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Pursuant to Section 302A.626 (subd. 7) of the MBCA, the provisions of the Restated Articles of Incorporation and Restated Bylaws of the Company are consistent with those of Old Otter Tail prior to the Merger. The authorized common shares and cumulative preferred shares of the Company, the designations, rights, powers and preferences of such shares and the qualifications, limitations and restrictions thereof are also consistent with those of Old Otter Tail s common shares and cumulative preferred shares immediately prior to the Merger. The directors and executive officers of the Company are the same individuals who were directors and executive officers, respectively, of Old Otter Tail immediately prior to the Merger.

Immediately prior to the Merger, Old Otter Tail transferred to the Company by means of assignment the capital stock of its direct subsidiaries and all of its other assets not specific to the operation of the electric utility business. As a result, the Company is a holding company with two primary subsidiaries, Otter Tail Power Company (the electric utility) and Varistar Corporation (a holding company for the nonelectric utility businesses).

The following table provides a breakdown of the assignment of the Company s consolidated short-term and long-term debt outstanding as of July 1, 2009.

(in thousands)	Otter Tail Power Company	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Lines of Credit	$ 19,914		$100,000	$119,914
Term Loan, Variable 3.81% at July 1, 2009, due May 20, 2011	$ 75,000			$ 75,000
Senior Unsecured Notes 6.63%, due December 1, 2011	90,000			90,000
Pollution Control Refunding Revenue Bonds, Variable, 3.50% at July 1, 2009, due December 1, 2012	10,400			10,400
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,165			5,165
Senior Unsecured Note 8.89%, due November 30, 2017			$ 50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,580			20,580
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Obligations of Varistar Corporation Various up to 8.25% at July 1, 2009		$7,289		7,289
Total	$356,145	$7,289	$ 50,000	$413,434
Less:				

Current Maturities		1,242		1,242
Unamortized Debt Discount		357		357
Total Long-Term Debt	$356,145	$5,690	$ 50,000	$411,835
Total Short-Term and Long-Term Debt (with current maturities)	$376,059	$6,932	$150,000	$532,991

The Company has evaluated events occurring through August 6, 2009 and determined there are no other events that have occurred subsequent to June 30, 2009 that would affect the Company s financial statements as of, and for the periods ending, June 30, 2009, or require additional disclosure in this report on Form 10-Q.

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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 and six months ended June 30, 2009 and 2008, followed by our outlook for the remainder of 2009 and a discussion of changes in our consolidated financial position during the six months ended June 30, 2009.

Comparison of the Three Months Ended June 30, 2009 and 2008

Consolidated operating revenues were $246.9 million for the three months ended June 30, 2009 compared with $323.6 million for the three months ended June 30, 2008. Operating income was $6.2 million for the three months ended June 30, 2009 compared with $10.3 million for the three months ended June 30, 2008. The Company recorded diluted earnings per share of $0.07 for the three months ended June 30, 2009 compared with $0.11 for the three months ended June 30, 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 June 30, 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)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
Operating Revenues:		
Electric	$ 53	$ 89
Nonelectric	1,149	697
Cost of Goods Sold	1,186	599
Other Nonelectric Expenses	16	187

Electric

(in thousands)	Three Months Ended June 30, 2009	2008	Change	% Change
Retail Sales Revenues	$61,273	$57,389	$ 3,884	6.8
Wholesale Revenues	3,272	6,221	(2,949)	(47.4)
Net Marked-to-Market Gain (Loss)	140	(31)	171	
Other Revenues	5,978	5,087	891	17.5
Total Operating Revenues	$70,663	$68,666	$ 1,997	2.9
Production Fuel	11,754	14,808	(3,054)	(20.6)
Purchased Power System Use	11,877	10,156	1,721	16.9
Other Operation and Maintenance Expenses	28,959	27,757	1,202	4.3
Depreciation and Amortization	8,998	7,806	1,192	15.3
Property Taxes	2,255	2,563	(308)	(12.0)
Operating Income	$ 6,820	$ 5,576	$ 1,244	22.3

The main factors contributing to the increase in retail sales revenues are: (1) a $2.2 million increase in Minnesota resource recovery rider revenues related to generation from the electric utility s wind turbines constructed in 2007 and 2008, (2) a $1.5 million increase related to a Minnesota interim rate revenue refund accrued in the second quarter of 2008 based on a granted rate increase of 2.9% compared to an interim rate increase of 5.4% that went into effect on

November 30, 2007, (3) a $0.6 million increase in North Dakota interim rates, and (4) a 1.3% increase in retail kilowatt-hour (kwh) sales, offset by a decrease in Fuel Clause Adjustment (FCA) revenues related to a $0.7 million reduction in fuel and purchased power costs for retail use.

Wholesale electric revenues from sales from company-owned generation were $2.6 million for the quarter ended June 30, 2009 compared with $4.9 million for the quarter ended June 30, 2008. Reduced plant availability and lower wholesale prices resulted in a 19.6% decrease in wholesale kwh sales and a 34.1% decrease in revenue per kwh sold. Fuel costs related to wholesale sales decreased $0.6 million between the quarters as a result of the decrease in wholesale kwh sales. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $0.8 million for the quarter ended June 30, 2009 compared with $1.2 million for the quarter ended June 30, 2008. The $0.9 million increase in other electric operating revenues is due to an increase in revenues from transmission permitting work of $1.3 million, partially offset by a $0.4 million reduction in revenues from other transmission-related services.

The decrease in fuel costs reflects a 23.8% decrease in kwhs generated from the electric utility s fossil fuel-fired plants, partially offset by a 4.1% increase in the cost of fuel per kwh generated. The decrease in kwhs generated and the increase in the average cost of fuel per kwh generated was due to a reduction in the availability of company-owned generation mainly resulting from a six-week scheduled maintenance shutdown of Coyote Station, the electric utility s lowest cost generation unit in terms of fuel costs per kwh. Generation for retail sales decreased 18.0% and generation used for wholesale electric sales decreased 19.6% between the quarters.

The increase in purchased power system use is due to a 92.3% increase in kwhs purchased to make up for the reduction in the availability of company-owned generation. Despite the 92.3% increase in kwh purchases, purchased power costs increased by only 16.9% as a result of a 39.2% decrease in the cost per kwh purchased. Decreases in natural gas prices, increased output from regional hydroelectric plants, increased efficiency in wholesale electric markets and a decline in industrial demand for electricity are factors that have contributed to a significant decline in wholesale electric prices in 2009.

The increase in other operating and maintenance expenses mainly is due to a $1.3 million increase in costs related to transmission permitting work performed for other entities. The increase in depreciation expense mainly is due to the addition of 32 wind turbines at the Ashtabula Wind Energy Center to utility plant in service at the end of 2008. The decrease in property taxes is related to reductions in valuations of utility property in Minnesota and on Big Stone Plant in South Dakota.

Plastics

	Three Months Ended June 30,			%
(in thousands)	2009	2008	Change	Change
Operating Revenues	$22,183	$40,645	$(18,462)	(45.4)
Cost of Goods Sold	19,679	36,685	(17,006)	(46.4)
Operating Expenses	1,136	1,829	(693)	(37.9)
Depreciation and Amortization	717	723	(6)	(0.8)
Operating Income	$ 651	$ 1,408	$ (757)	(53.8)

Operating revenues and operating income for the plastics segment decreased as result of a 28.8% decrease in pounds of pipe sold. A 23.1% decrease in polyvinyl chloride (PVC) pipe prices also contributed to the decrease in operating revenues. The decrease in costs of goods sold was due to the decrease in pounds of pipe sold and a 30.7% decrease in costs per pound of PVC pipe sold. The decrease in operating expenses includes a $0.4 million reduction in sales commissions, salaries and other sales related expenses. Also, operating expenses in the second quarter of 2008 included $0.3 million in losses on asset sales. 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 June 30, 2009	2008	Change	% Change
Operating Revenues	$76,843	$120,342	$(43,499)	(36.1)
Cost of Goods Sold	59,908	99,377	(39,469)	(39.7)
Operating Expenses	10,364	10,213	151	1.5
Plant Closure Costs		1,412	(1,412)	
Depreciation and Amortization	5,666	4,876	790	16.2
Operating Income	$ 905	$ 4,464	$ (3,559)	(79.7)

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

Revenues at DMI Industries, Inc. (DMI) decreased $25.3 million due to a 42.1% decrease in volume of towers produced, mainly as a result of delays or suspension of orders related to the economic recession and wind developers limited access to financing.

Revenues at BTD Manufacturing, Inc. (BTD) decreased $7.6 million as a result of a $6.7 million decrease in sales volume and a $0.9 million decrease in scrap sales.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) decreased $1.8 million due to a decrease in sales volumes across product lines.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $8.8 million due to decreases in both residential and commercial sales related to the current economic recession and credit restraints affecting dealers and consumers.

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

Cost of goods sold at DMI decreased $26.9 million as a result of reductions in production and sales of wind towers related to current economic conditions. Also, cost of goods sold in the second quarter of 2008 included $2.0 million in costs associated with the start up of DMI s Oklahoma plant.

Cost of goods sold at BTD decreased $5.0 million as a result of reduced sales and lower productivity.

Cost of goods sold at T.O. Plastics decreased $1.9 million mainly as a result of a decrease in volume of products sold.

Cost of goods sold at ShoreMaster decreased $5.7 million mainly due to a decrease in sales of residential and commercial products.

The net increase in operating expenses in our manufacturing segment is due to the following:

Operating expenses at DMI decreased $0.2 million, reflecting a decrease in repairs and maintenance expenses.

Operating expenses at BTD decreased $0.3 million due to a reduction in bonuses and incentives directly related to the decrease in sales and revenue.

Operating expenses at ShoreMaster increased $0.6 million as a result of additional costs related to a marina construction project.

Operating expenses at T.O. Plastics increased by less than $0.1 million between the quarters.
The $1.4 million in plant closure costs in the second quarter of 2008 includes employee-related termination obligations, asset impairment costs and a reserve for additional expenses incurred related to the closing of ShoreMaster s production facility in California following the completion of a major marina project in the state in 2008. Depreciation expense increased as a result of capital additions at DMI and the acquisition of Miller Welding & Iron Works (Miller Welding) in May 2008.

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Health Services

(in thousands)	Three Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$28,192	$30,740	$(2,548)	(8.3)
Cost of Goods Sold	22,431	24,128	(1,697)	(7.0)
Operating Expenses	4,871	5,534	(663)	(12.0)
Depreciation and Amortization	972	1,013	(41)	(4.0)
Operating (Loss) Income	$ (82)	$ 65	$ (147)	(226.2)

Revenues from scanning and other related services were down $1.7 million and revenues from equipment sales and servicing decreased $0.8 million for the three months ended June 30, 2009 compared with the three months ended June 30, 2008. The decrease in cost of goods sold was directly related to the decreases in sales revenue. The decrease in operating expenses is the result of measures taken to control and reduce operating expenses. Also, operating expenses in the second quarter of 2008 are net of a $0.4 million gain on the sale of fixed assets. 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 June 30, 2009	2008	Change	% Change
Operating Revenues	$20,581	$15,913	$4,668	29.3
Cost of Goods Sold	14,781	12,717	2,064	16.2
Operating Expenses	787	828	(41)	(5.0)
Depreciation and Amortization	1,067	1,071	(4)	(0.4)
Operating Income	$ 3,946	$ 1,297	$2,649	204.2

The increase in food ingredient processing revenues is due to a 12.8% increase in pounds of product sold, combined with a 14.7% increase in the price per pound of product sold. Cost of goods sold increased as a result of the increase in sales and a 3.1% increase in the cost per pound of product sold.

Other Business Operations

(in thousands)	Three Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$29,597	$48,080	$(18,483)	(38.4)
Cost of Goods Sold	19,706	31,927	(12,221)	(38.3)
Operating Expenses	11,577	14,053	(2,476)	(17.6)
Depreciation and Amortization	586	497	89	17.9
Operating (Loss) Income	$ (2,272)	$ 1,603	$ (3,875)	(241.7)

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

Revenues at Foley Company decreased $9.6 million due to a decrease in volume of jobs in progress related to the current economic recession and increased competition for available work.

Revenues at Aevenia, Inc. (Aevenia), formerly Midwest Construction Services, Inc., decreased $6.1 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 E.W. Wylie Corporation (Wylie) decreased $2.8 million as a result of lower diesel fuel prices being passed through to customers and a 16.9% reduction in miles driven by company-owned trucks directly related to the current economic recession.

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

Cost of goods sold at Foley Company decreased $8.2 million as a result of decreases in construction activity and jobs in progress.

Cost of goods sold at Aevenia decreased $4.0 million as a result of a reduction of jobs in progress.

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

Operating expenses at Wylie decreased $1.9 million between the quarters. Fuel costs decreased $2.3 million as a result of a 48.0% decrease in fuel costs per gallon combined with the 16.9% decrease in miles driven by company-owned trucks. Subcontractor expenses decreased $0.6 million as a result of the decrease in fuel costs per gallon. The decreases in fuel costs were partially offset by an increase in equipment repair expenses of $0.5 million and an increase in rent expenses of $0.4 million, mainly related to additional equipment leases.

Operating expenses at Aevenia decreased $0.5 million between the quarters directly related to initiatives to control costs and reduce expenses.

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 June 30,			%
(in thousands)	2009	2008	Change	Change
Operating Expenses	$3,691	$3,972	$(281)	(7.1)
Depreciation and Amortization	97	138	(41)	(29.7)

The decrease in corporate operating expenses reflects reductions in health care benefit costs.

Interest Charges

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

Other Income

Other income increased $0.7 million in the in the second quarter of 2009 compared with the second quarter of 2008 mainly as a result of a $0.5 million increase in allowance for funds used during construction (AFUDC) at the electric utility.

Income Taxes

The $2.2 million decrease in income taxes between the quarters is partly the result of a $3.0 million (77.4%) decrease in income before income taxes for the three months ended June 30, 2009 compared with the three months ended June 30, 2008. The effective tax rate for the three months ended June 30, 2009 was lower than the effective tax rate for the three months ended June 30, 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 $1.8 million in the second quarter of 2009 compared with $0.9 million in the second 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.

Comparison of the Six Months Ended June 30, 2009 and 2008

Consolidated operating revenues were $524.1 million for the six months ended June 30, 2009 compared with $623.8 million for the six months ended June 30, 2008. Operating income was $14.8 million for the six months ended June 30, 2009 compared with $27.4 million for the six months ended June 30, 2008. The Company recorded diluted earnings per share of $0.19 for the six months ended June 30, 2009 compared with $0.38 for the six months ended June 30, 2008.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six month periods ended June 30, 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)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating Revenues:		
Electric	$ 115	$ 173
Nonelectric	2,086	1,184
Cost of Goods Sold	2,026	1,065
Other Nonelectric Expenses	175	292

Electric

(in thousands)	Six Months Ended June 30, 2009	2008	Change	% Change
Retail Sales Revenues	$140,328	$144,689	$(4,361)	(3.0)
Wholesale Revenues	8,035	9,805	(1,770)	(18.1)
Net Marked-to-Market Gain	1,174	2,219	(1,045)	(47.1)
Other Revenues	9,667	9,543	124	1.3
Total Operating Revenues	$159,204	$166,256	$(7,052)	(4.2)
Production Fuel	30,413	34,712	(4,299)	(12.4)
Purchased Power System Use	29,250	29,142	108	0.4
Other Operation and Maintenance Expenses	55,889	54,500	1,389	2.5
Depreciation and Amortization	17,986	15,514	2,472	15.9
Property Taxes	4,745	5,187	(442)	(8.5)
Operating Income	$ 20,921	$ 27,201	$(6,280)	(23.1)

The main reason for the decline in retail sales revenue was an $11.1 million decrease in fuel cost recovery revenues mainly related to a decrease in costs per kwh for fuel and purchased power between the periods and a $0.5 million increase in a Minnesota interim rate refund payable in the first quarter of 2009. These revenue decreases were partially offset by: (1) a $3.9 million increase in Minnesota resource recovery rider revenues, (2) $2.1 million in revenues related to a North Dakota effective interim rate increase of 3.04% in 2009 (reduced from 4.1% in June 2009) and (3) a $1.7 million increase in North Dakota resource recovery rider revenues.

Wholesale electric revenues from sales from company-owned generation were $7.0 million for the six months ended June 30, 2009 compared with $9.1 million for the six months ended June 30, 2008 as a result of a 35.3% decrease in the average price per kwh sold, partially offset by a 19.5% increase in wholesale kwh sales. Fuel costs related to wholesale sales decreased $0.2 million between the quarters despite the increase in wholesale kwh sales as a result of reductions in fuel costs and generation at the electric utility s combustion turbine peaking plants. 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 $2.2 million for the six months ended June 30, 2009 compared with $2.9 million for the six months ended June 30, 2008 as a result of a reduction in volume of energy trades and energy trading activity between the periods.

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The decrease in fuel costs reflects a 14.8% decrease in kwhs generated from the electric utility s fossil fuel-fired plants, partially offset by a 2.9% increase in the cost of fuel per kwh generated at those plants. A 9.3% increase in the average cost of fuel per kwh of generation at the electric utility s coal-fired plants was partially offset by a 61.1% 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 9.7% of total kwh generation in the first six months of 2009 compared with 3.3% in the first six months of 2008. Generation for retail sales decreased 11.4% while generation used for wholesale electric sales increased 19.5% between the periods.

The increase in purchased power system use is due to a 64.7% increase in kwhs purchased, mostly offset by a 39.0% reduction in the cost per kwh purchased. The increase in kwh purchases for system use is related to a reduction in the availability of company-owned generation resulting from maintenance outages at Big Stone Plant and a six-week scheduled maintenance shutdown of Coyote Station in the second quarter of 2009. 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 sources.

The increase in other operating and maintenance expenses mainly is due to a $0.8 million increase in incentive accruals and wage increases for union employees. The increase in depreciation expense mainly is due to the addition of 32 wind turbines at the Ashtabula Wind Energy Center to utility plant in service at the end of 2008. The decrease in property taxes is related to reductions in valuations of utility property in Minnesota and on Big Stone Plant in South Dakota.

Plastics

	Six Months Ended June 30,			%
(in thousands)	2009	2008	Change	Change
Operating Revenues	$35,713	$62,995	$(27,282)	(43.3)
Cost of Goods Sold	35,031	55,621	(20,590)	(37.0)
Operating Expenses	2,511	3,267	(756)	(23.1)
Depreciation and Amortization	1,433	1,518	(85)	(5.6)
Operating (Loss) Income	$ (3,262)	$ 2,589	$ (5,851)	(226.0)

Operating revenues and operating income for the plastics segment decreased as result of a 25.3% decrease in pounds of pipe sold. A 23.9% decrease in PVC pipe prices also contributed to the decrease in operating revenues. The decrease in costs of goods sold was due to the decrease in pounds of pipe sold and a 21.2% decrease in costs per pound of PVC pipe sold. The decrease in operating expenses includes a $0.4 million reduction in sales commissions, salaries and other sales related expenses. Also, operating expenses in 2008 included $0.3 million in losses on asset sales. 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)	Six Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$172,862	$217,937	$(45,075)	(20.7)
Cost of Goods Sold	139,443	182,225	(42,782)	(23.5)
Operating Expenses	20,410	20,536	(126)	(0.6)
Product Recall and Testing Costs	1,766		1,766	
Plant Closure Costs		1,412	(1,412)	
Depreciation and Amortization	11,024	8,625	2,399	27.8
Operating Income	$ 219	$ 5,139	$ (4,920)	(95.7)

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

Revenues at DMI decreased $23.6 million due to a 20.1% decrease in volume of towers produced, mainly as a result of delays or suspension of orders related to the economic recession and wind developers limited access to financing.

Revenues at BTD decreased $3.8 million as a result of a $7.2 million decrease in sales volume and a $1.6 million decrease in scrap sales revenue related to lower steel prices, partially offset by a $5.0 million increase in revenues from Miller Welding, acquired in May 2008.

Revenues at T.O. Plastics decreased $6.4 million due to a decrease in volume of products sold as customers utilized existing inventory in the channel.

Revenues at ShoreMaster decreased $11.3 million due to decreases in both residential and commercial sales related to the current economic recession and credit restraints affecting dealers and consumers.

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

Cost of goods sold at DMI decreased $29.4 million as a result of reductions in production and sales of wind towers related to current economic conditions. Also, cost of goods sold in the first six months of 2008 included $3.2 million in additional labor and material costs on a production contract at the Fort Erie plant and $2.8 million in costs associated with the start up of DMI s Oklahoma plant.

Cost of goods sold at BTD decreased $0.3 million. A decrease of $5.5 million in cost of goods sold related to a decrease in sales volume was offset by a $3.6 million increase in costs of goods sold at Miller Welding, acquired in May 2008 and $1.5 million in unabsorbed overhead costs due to lower productivity.

Cost of goods sold at T.O. Plastics decreased $5.7 million mainly as a result of a decrease in volume of products sold.

Cost of goods sold at ShoreMaster decreased $7.4 million mainly due to a decrease in sales of residential and commercial products partially offset by $0.9 million in additional costs recorded on a marina construction project.

Operating expenses at each of the companies in our manufacturing segment were essentially unchanged between the periods.

The $1.8 million in product recall and testing costs in 2009 includes 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 at ShoreMaster.

The $1.4 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and a reserve for additional expenses related to the closing of ShoreMaster s production facility in California following the completion of a major marina project in the state in 2008.

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

Health Services

(in thousands)	Six Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$56,359	$60,005	$(3,646)	(6.1)
Cost of Goods Sold	44,568	47,419	(2,851)	(6.0)
Operating Expenses	9,960	11,459	(1,499)	(13.1)
Depreciation and Amortization	1,962	1,995	(33)	(1.7)
Operating (Loss)	$ (131)	$ (868)	$ 737	84.9

Revenues from scanning and other related services were down $2.6 million and revenues from equipment sales and servicing decreased $1.0 million for the six months ended June 30, 2009 compared with the six months ended June 30, 2008. The decrease in cost of goods sold was directly related to the decreases in sales revenue. The decrease in operating expenses is the result of measures taken to control and reduce operating expenses. Also, operating expenses in the first half of 2008 are net of a $0.4 million gain on the sale of fixed assets. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

Food Ingredient Processing

(in thousands)	Six Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$40,667	$31,811	$8,856	27.8
Cost of Goods Sold	30,763	25,036	5,727	22.9
Operating Expenses	1,599	1,641	(42)	(2.6)
Depreciation and Amortization	2,108	2,144	(36)	(1.7)
Operating Income	$ 6,197	$ 2,990	$3,207	107.3

The increase in food ingredient processing revenues is due to a 10.2% increase in pounds of product sold, combined with a 16.0% increase in the price per pound of product sold. Cost of goods sold increased as a result of the increase in sales and an 11.5% increase in the cost per pound of product sold.

Other Business Operations

(in thousands)	Six Months Ended June 30, 2009	2008	Change	% Change
Operating Revenues	$61,492	$86,190	$(24,698)	(28.7)
Cost of Goods Sold	40,501	60,222	(19,721)	(32.7)
Operating Expenses	22,438	26,066	(3,628)	(13.9)
Depreciation and Amortization	1,210	958	252	26.3
Operating Loss	$ (2,657)	$ (1,056)	$ (1,601)	(151.6)

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

Revenues at Foley Company decreased $11.0 million due to a decrease in volume of jobs in progress related to the current economic recession and increased competition for available work.

Revenues at Aevenia decreased $8.8 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 Wylie decreased $4.9 million due to a 23.3% reduction in miles driven by company-owned 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 Foley Company decreased $11.5 million as a result of decreases in construction activity and jobs in progress.

Cost of goods sold at Aevenia decreased $8.2 million as a result of a reduction of jobs in progress.

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

Operating expenses at Wylie decreased $3.3 million between the periods. Fuel costs decreased $3.4 million as a result of a 46.6% decrease in fuel costs per gallon combined with the 23.3% decrease in miles driven by company-owned trucks. Subcontractor expenses decreased $1.1 million as a result of the decrease in fuel costs per gallon. The decreases in fuel costs were partially offset by an increase in repair and maintenance expenses of $0.5 million and an increase in rent expenses of $0.6 million, mainly related to additional equipment leases.

Operating expenses at Aevenia decreased $0.2 million between the periods.

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.

	Six Months Ended June 30,			%
(in thousands)	2009	2008	Change	Change
Operating Expenses	$6,301	$8,312	$(2,011)	(24.2)
Depreciation and Amortization	197	283	(86)	(30.4)

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

Interest Charges

Interest charges decreased $0.8 million in the first six months of 2009 compared with the first six months of 2008 as a result of decreases in short-term debt interest rates and average short-term debt outstanding between the periods.

Other Income

Other income increased $0.4 million in the first six months of 2009 compared with the first six months of 2008 as a result of a $0.2 million increase in AFUDC at the electric utility and a $0.2 million increase in foreign currency exchange gains from DMI s Canadian operations.

Income Taxes

The $6.7 million decrease in income taxes between the quarters is primarily the result of an $11.3 million decrease in income before income taxes for the six months ended June 30, 2009 compared with the six months ended June 30, 2008. The effective tax rate for the six months ended June 30, 2009 was lower than the effective tax rate for the six months ended June 30, 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 $3.9 million in the first six months of 2009 compared with $1.5 million in the first six months 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.

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 $0.70 to $1.10 per diluted share from our previously announced range of $0.80 to $1.20. 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 our earnings guidance for 2009 are the following items:

We now expect 2009 earnings from our electric segment to be in line with 2008 earnings. While 2009 earnings are expected to be impacted by lower than requested electric revenue increases in North Dakota and South Dakota and lower volumes and margins from wholesale energy sales, the electric utility has benefited from continued cost reduction efforts and higher than expected earnings from AFUDC related to construction of the Luverne Wind Farm.

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 our manufacturing segment to break even in 2009 as a result of the following:

- o BTD experienced continued unexpected declines in customer demand in the second quarter of 2009 and expects soft demand to continue for the rest of the year resulting in lower earnings compared with 2008.

- o While the economy is expected to reduce the amount of spending on waterfront products, net losses 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. ShoreMaster continues to experience performance issues on a marina construction project which is having a negative effect on its results of operations.

- o DMI s earnings in 2009 are expected to decline due to the sluggish economy and 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.

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

- o Backlog in place in the manufacturing segment to support revenues for the remainder of 2009 is approximately $92 million compared with $206 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, lower energy costs and higher production levels in 2009 compared with 2008.

We now expect our other business operations segment to have lower earnings in 2009 compared with 2008. The decline in construction projects in 2009 due to poor economic conditions has negatively affected our construction companies. Our trucking operations continue to be impacted by lower selling prices and volumes in its heavy haul business. Backlog in place for the construction businesses is $42 million for the remainder of 2009 compared with $79 million one year ago.

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

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FINANCIAL POSITION

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

(in thousands)	Line Limit	In Use on July 31, 2009	Restricted due to Outstanding Letters of Credit	Available on July 31, 2009	Available on December 31, 2008
Otter Tail Corporation Credit Agreement	$200,000	$112,000	$ 14,345	$ 73,655	$ 77,706
Electric Utility Credit Agreement	170,000			170,000	142,935
Total	$370,000	$112,000	$ 14,345	$243,655	$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.

Prior to Otter Tail Corporation s holding company reorganization on July 1, 2009, the Company s wholly owned subsidiary, Varistar Corporation (Varistar), was the borrower under a $200 million credit agreement (the 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. Effective July 1, 2009 all of Varistar s rights and obligations under the Credit Agreement were assigned to and assumed by Otter Tail Corporation. Beginning July 1, 2009 borrowings bear interest at LIBOR plus 2.375%, subject to adjustment based on the senior unsecured credit ratings of the Company. The Credit Agreement expires October 2, 2010 and is an unsecured revolving credit facility. The Credit Agreement contains a number of restrictions on the Company and 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 Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower s credit ratings. The Company s obligations under the Credit Agreement are guaranteed by Varistar and its material subsidiaries. Outstanding letters of credit issued by the borrower under the Credit Agreement can reduce the amount available for borrowing under the line by up to $30 million. The Credit Agreement has an accordion feature whereby the line can be increased to $300 million as described in the Credit Agreement.

Prior to the Company s holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now Otter Tail Power Company) was the borrower under 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 Electric Utility Credit Agreement. The credit agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now 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

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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 the borrower s 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. Following the Company s holding company reorganization, the Electric Utility Credit Agreement is an obligation of Otter Tail Power Company.

Prior to the Company s holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now Otter Tail Power Company) was the borrower under a $75 million term loan agreement (the Electric Utility Loan Agreement). The Electric Utility Loan Agreement was entered into between Otter Tail Corporation, d/b/a Otter Tail Power Company (now Otter Tail Power Company) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. The Electric Utility Loan Agreement provides for a $75 million term loan due May 20, 2011, which Otter Tail Power Company is using to support the working capital needs and other capital requirements of its electric operations, including construction of the Luverne Wind Farm in North Dakota. Borrowings under the Electric Utility Loan Agreement currently bear interest at a rate equal to the base rate in effect from time to time. The base rate is a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A. s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of Otter Tail Power Company s senior unsecured credit ratings, as provided in the Electric Utility Loan Agreement. At Otter Tail Power Company s option, the interest rate on outstanding borrowings may be converted to a LIBOR rate that would fluctuate based on the rate at which deposits of U.S. dollars in the London interbank market are quoted, plus a margin of 2.5% to 4.0% determined on the basis of Otter Tail Power Company s senior unsecured credit ratings, as provided in the Electric Utility Loan Agreement. The interest rate on borrowings under the Electric Utility Loan Agreement was 3.81% at June 30, 2009. The Electric Utility Loan Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Following the Company s holding company reorganization, the Electric Utility Loan Agreement is an obligation of Otter Tail Power Company.

The note purchase agreement relating to the $90 million 6.63% senior notes due December 1, 2011 entered into in December 2001 by Otter Tail Corporation (now known as Otter Tail Power Company), as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to the $50 million 5.778% senior note due November 30, 2017 entered into in February 2007 by Otter Tail Corporation (now known as Otter Tail Power Company) and assigned to the Company (formerly known as Otter Tail Holding Company), 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, entered into in August 2007 by Otter Tail Corporation (now known as Otter Tail Power Company), as amended (the 2007 Note Purchase Agreement) each states that the applicable obligor 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 the applicable obligor 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 the applicable obligor 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 such obligor. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor s ability and the ability of the obligor s 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. Prior to the effectiveness of the holding company reorganization, the Company s obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement were guaranteed by Varistar and certain of its material subsidiaries. Following the effectiveness of the holding company reorganization, only the obligations of the Company under the Cascade Note Purchase Agreement remain guaranteed by Varistar and certain of its material subsidiaries (and not by Otter Tail Power Company).

Financial Covenants

As of June 30, 2009 the Company was in compliance with the financial statement covenants that existed in its debt agreements as defined in those agreements prior to the holding company reorganization.

None of the Credit and Note Purchase Agreements contains any provisions that would trigger an acceleration of the related debt caused by credit rating levels assigned to the related obligor by rating agencies.

Following the Company s holding company reorganization on July 1, 2009: (1) the Varistar Credit Agreement is an obligation of the Company, as assignee of Varistar, guaranteed by Varistar and its material subsidiaries, (2) the Cascade Note Purchase Agreement is an obligation of the Company, as assignee of Otter Tail Corporation (now Otter Tail Power Company) prior to the reorganization, guaranteed by Varistar and its material subsidiaries, and (3) the Electric Utility Credit Agreement, the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement are obligations of Otter Tail Power Company.

Following the Company s holding company reorganization on July 1, 2009 the Company s borrowing agreements are subject to certain financial covenants. Specifically:

Under the credit agreement relating to the $200 million credit facility of the Company (as assignee of Varistar Corporation), the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the credit agreement.

Under the Cascade Note Purchase Agreement, the Company may not permit its Consolidated Debt to exceed 60% of Consolidated Total Capitalization or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the Debt of Otter Tail Power Company to exceed 60% of Otter Power Consolidated Total Capitalization, or permit the Priority Debt of Varistar and its subsidiaries to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.

Under the Loan Agreement and the credit agreement relating to Otter Tail Power Company s $170 million credit facility, Otter Tail Power Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.

Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, Otter Tail Power Company may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, Otter Tail Power Company may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

Our securities ratings at July 31, 2009 were:

Otter Tail Corporation	Moody s Investors Service	Fitch Ratings	Standard & Poor s
Corporate/Long-term Issuer Default Rating	Baa3	BBB-	BBB-
Senior Unsecured Debt	Baa3	BBB-	BB+
Outlook	Stable	Stable	Stable

Otter Tail Power Company	Moody s Investors Service	Fitch Ratings	Standard & Poor s

Corporate/Long-term Issuer Default Rating	A3	BBB	BBB-
Senior Unsecured Debt	A3	BBB+	BBB-
Outlook	Stable	Stable	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.
DMI has a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $64.8 million were sold in the first six months of 2009. Discounts, fees and commissions of $267,000 for the six months ended June 30, 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 June 30, 2009 was $16.4 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 $3.9 million on June 30, 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 $90.3 million for the six months ended June 30, 2009 compared with cash provided by operating activities of $34.9 million for the six months ended June 30, 2008. The $55.4 million increase in cash from operating activities reflects a $47.1 million increase in cash from working capital items, a $3.7 million increase in cash related to increases in deferred income taxes, a $3.1 million increase in cash related to changes in noncurrent liabilities and deferred credits and $2.1 million related to a decrease in cash used for deferred debits and other assets between the periods.
Major sources of funds from working capital items in the first six months of 2009 were a decrease in receivables of $33.3 million, a decrease in other current assets of $18.7 million, a decrease in interest and income taxes payable/receivable of $14.3 million and a decrease in inventories of $10.1 million, offset by a decrease in payables and other current liabilities of $41.2 million. The $33.3 million decrease in accounts receivable reflects decreases in trade receivables in our manufacturing and construction segments 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 $18.7 million decrease in other current assets includes: (1) a decrease of $15.4 million in costs in excess of billings at DMI as a result of decreased production activity and (2) a $12.1 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 $7.2 million increase in prepaid expenses primarily related to the payment of 2009 insurance premiums. The $14.3 million decrease in interest and income taxes payable/receivable is mainly related to the receipt of a $26.3 million federal income tax refund in May 2009 related to the application of 2008 tax credits and losses related to bonus depreciation to tax liabilities paid in previous years. The receipt of the tax refund was partially offset by recent reductions in income tax expenses combined with the accrual of renewable energy tax credits earned in the first half of 2009. The $10.1 million decrease in inventories is mostly due to an

$8.6 million reduction in inventories at the plastic pipe companies related to reductions in production and sales and raw material costs. The $41.2 million decrease in payables and other current liabilities includes: (1) a $15.7 million reduction in accounts payable at DMI mainly related to steel purchases, (2) $10.3 million related to the payment of accrued wages and benefits in the first half of 2009, (3) an $8.1 million reduction in accounts payable at the electric utility related to reductions in purchased power costs and interim rate refunds credited to Minnesota customers in 2009, and (4) a $5.4 million decrease in accounts payable at Foley Company related to a reduction in construction activity in 2009.

Net cash used in investing activities was $120.0 million for the six months ended June 30, 2009 compared with $156.3 million for the six months ended June 30, 2008. Cash used for capital expenditures decreased by $59.9 million between the periods mainly due to a decrease in capital expenditures at the electric utility for payments in the first six months of 2008 related to the construction of 27 wind turbines at the Langdon Wind Energy Center. Cash used for capital expenditures of $57.9 million in the first six months of 2009 includes $35.8 million at the electric utility for payments mainly related to the construction of 32 wind turbines at Ashtabula Wind Energy Center and the start of construction of 33 wind turbines at the Luverne Wind Farm. We paid $41.7 million in cash to acquire Miller Welding in May 2008. The $66.3 million increase in other investments and long-term assets includes the deposit of $64.0 million in cash in an escrow account to be used for the purchase of wind turbines for the electric utility s Luverne Wind Farm.

Net cash provided by financing activities was $31.6 million for the six months ended June 30, 2009 compared with $81.4 million for the six months ended June 30, 2008. Reductions in short-term borrowings of $15.0 million in the first half of 2009 compared to proceeds from short-term borrowings of $91.6 million used to fund a portion of capital expenditures in the first half of 2008. We borrowed $75.0 million in May 2009 under a two-year term loan agreement. The proceeds are being used to support the working capital needs and other capital requirements of our electric operations, including construction of the Luverne Wind Farm in North Dakota. We paid $3.2 million in short-term and long-term debt issuance expenses in the first half of 2009. We made payments of $5.4 million for the retirement of long-term debt in the first half of 2009 compared with $1.8 million in the first half of 2008. The $3.6 million increase in payments for the retirement of long-term debt between the periods reflects a $3.5 million payment for the early retirement of our Lombard US Equipment Finance Note. We paid $21.5 million in dividends on common and preferred shares in the first half of 2009 compared with $18.2 million in the first half of 2008. The increase in dividend payments is due to an increase in common shares outstanding between the periods mainly related to our September 2008 common stock offering.

Due to the approval of additional capital expenditures for our electric segment in 2009 related to construction of the Luverne Wind Farm, we have revised our estimated capital expenditures for our electric segment for 2009 and the years 2009 through 2013 from those presented on page 27 of our 2008 Annual Report to Shareholders as presented in the following table:

(in millions)	2009	2009-2013
Electric	$140	$803
Plastics	5	18
Manufacturing	13	115
Health Services	3	27
Food Ingredient Processing	3	14
Other Business Operations	2	11
Corporate		1
Total	$166	$989

The following items have increased our contractual obligations from those reported in the table under the caption Capital Requirements on page 27 of our 2008 Annual Report to Shareholders: (1) our long-term debt obligations have increased by $75.0 million in 2011 as a result of borrowing $75 million under a variable rate term loan agreement in May 2009, (2) our interest on long-term debt obligations has increased by $1.8 million in 2009, $2.9 million in 2010 and $1.1 million in 2011 related to the $75 million borrowed under a variable rate term loan agreement in May 2009, based on an annual interest rate of 3.81% in effect on June 30, 2009, (3) our purchase obligations have increased by $105 million in 2009 related to the electric utility s construction of 33 wind turbines underway at the Luverne Wind Farm in North Dakota, and by an additional $3.0 million in 2009 and $6.5 million in 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 June 30, 2009.

Goodwill Impairment

We currently have $12.3 million of goodwill and $4.9 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of ShoreMaster and its subsidiary companies. If current economic conditions continue to impact the amount of sales of waterfront products and ShoreMaster is not successful with reorganizing and streamlining its business to improve operating margins according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with ShoreMaster and a corresponding charge against earnings.

We currently have $24.3 million of goodwill and a $3.3 million nonamortizable trade name recorded on our balance sheet related to the acquisition of Idaho Pacific Holdings, Inc. (IPH) in 2004. If conditions of low sales prices, high energy and raw material costs and a shortage of raw potato supplies return, as experienced in 2006, or operating margins do not improve according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with IPH and a corresponding charge against earnings.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2008 an assessment of the carrying values of our goodwill indicated no impairment.

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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.
- 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 $12.8 million in costs related to the planned construction of a second electric generating unit at the Big Stone Plant site as of June 30, 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.
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 (CO_2) emission levels, taxes on CO_2 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 or manufacturing businesses could lead to adverse financial results.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

At July 1, 2009 we had exposure to market risk associated with interest rates because we had $100.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 2.375% under the Otter Tail Corporation Credit Agreement and $19.9 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the Otter Tail Power Company Credit Agreement. At June 30, 2009 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Fort Erie, Ontario because the plant pays its operating expenses in Canadian dollars. Outstanding trade accounts receivable of the Canadian operations of Idaho Pacific Holdings, Inc. (IPH) are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 13% of IPH sales in the first six months of 2009 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. However, IPH s Canadian subsidiary has locked in exchange rates for the exchange of U.S. dollars (USD) for Canadian dollars (CAD) for approximately 82% of its cash needs for July 2009 and approximately 50% of its cash needs for the period August 1, 2009 through October 31, 2009 by entering into forward foreign currency exchange contracts. On June 30, 2009 IPH s Canadian subsidiary held contracts for the exchange of $2.0 million USD for $2.4 million CAD.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of June 30, 2009 we had $85.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on June 30, 2009, annualized interest expense and pre-tax earnings would change by approximately $854,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, sales volume has been higher and when resin prices are falling, sales volumes has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

The companies in our manufacturing segment are exposed to market risk related to changes in commodity prices for steel, lumber, aluminum, cement and resin. The price and availability of these raw materials could affect the revenues and earnings of our manufacturing segment.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of June 30, 2009 the electric utility had recognized, on a pretax basis, $171,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity and electricity generating capacity 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. Of the forward energy sales contracts that are marked to market as of June 30, 2009, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods.

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We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. Exposure to price risk on any open positions as of June 30, 2009 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and electricity generating capacity on our consolidated balance sheet as of June 30, 2009 and the change in our consolidated balance sheet position from December 31, 2008 to June 30, 2009:

(in thousands)	June 30, 2009
Current Asset Marked-to-Market Gain	$ 3,595
Regulatory Asset Deferred Marked-to-Market Loss	629
Current Liability Marked-to-Market Loss	(3,727)
Regulatory Liability Deferred Marked-to-Market Gain	(326)
Net Fair Value of Marked-to-Market Energy Contracts	$ 171

(in thousands)	Year-to-Date June 30, 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	171
Net Fair Value End of Period	$ 171

The $171,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2009 is expected to be realized on settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	3rd Quarter 2009	1st Quarter 2010	Total
Net Gain	$ 131	$ 40	$ 171

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty s financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of June 30, 2009 was $2,156,000. As of June 30, 2009 we had a net credit risk exposure of $5,965,000 from ten counterparties with investment grade credit ratings and two 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. We had no exposure at June 30, 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 $5,965,000 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 June 30, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able to increase prices for its finished products to recover increases in fuel costs.

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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivatives and Hedging Instruments,* as amended and interpreted.
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 June 30, 2009:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in July 2008	July 2009	$ 400	$ 417
Contracts entered into in October 2008	July 2009 - October 2009	1,600	1,999
Contracts outstanding on June 30, 2009	July 2009 - October 2009	$2,000	$2,416

The following table shows the effect of marking to market IPH s foreign currency exchange forward windows on the Company s consolidated balance sheet as of June 30, 2009 and the change in the Company s consolidated balance sheet position from December 31, 2008 to June 30, 2009:

(in thousands)	Year-to-Date June 30, 2009
Fair Value at Beginning of Year	$ (289)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	277
Changes in Fair Value of Contracts Entered into in 2008	90
Net Fair Value of Contracts Entered into in 2008 at End of Period	78
Changes in Fair Value of Contracts Entered into in 2009	
Net Fair Value End of Period	$ 78

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 June 30, 2009 were valued and marked to market on June 30, 2009 based on quoted exchange values on June 30, 2009.
Item 4. Controls and Procedures
Under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of June 30, 2009, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer

and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of June 30, 2009.

During the fiscal quarter ended June 30, 2009, there were no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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 was denied on July 22, 2009. On July 31, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The ultimate outcome of this matter cannot be determined at this time.

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where it has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under the caption Risk Factors and Cautionary Statements on pages 29 through 32 of the Company s 2008 Annual Report to Shareholders, which is incorporated by reference to Part I, Item 1A, Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The Company does not have a publicly announced stock repurchase program. The following table shows previously issued common shares that were surrendered to the Company by employees to pay taxes in connection with the vesting of restricted stock granted to such employees under the Company s 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2009	2,996	$ 22.91
May 2009		
June 2009		

Total	2,996

Item 4. Submission of Matters to a Vote of Security Holders

The Annual Meeting of Shareholders of the Company was held on April 20, 2009, to consider and act upon the following matters: (1) to elect three nominees to the Board of Directors with terms expiring in 2012, and (2) to ratify the appointment of Deloitte & Touche LLP as the Company s independent registered public accounting firm for the fiscal year ending December 31, 2009. All nominees for directors as listed in the proxy statement were elected. The names of each other director whose term of office continued after the meeting are as follows: John D. Erickson, Arvid R. Liebe, John C. MacFarlane, Nathan I. Partain, Gary Spies and James B. Stake.

The voting results are as follows:

Election of Directors	Shares Voted For	Shares Voted Withheld Authority	Broker Non-Votes
Karen M. Bohn	28,981,892	1,054,877	-0-
Edward J. McIntyre	29,230,167	806,602	-0-
Joyce Nelson Schuette	29,042,627	994,142	-0-

	Shares Voted For	Shares Voted Against	Shares Voted Abstain	Broker Non-Votes
Ratification of Deloitte & Touche LLP as Independent Registered Public Accounting Firm	29,261,305	582,486	197,451	-0-

Item 6. Exhibits

2.1 Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc. (incorporated by reference to Exhibit 2.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)

3.1 Restated Articles of Incorporation of Otter Tail Corporation (incorporated by reference to Exhibit 3.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)

3.2 Restated Bylaws of Otter Tail Corporation (incorporated by reference to Exhibit 3.2 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)

4.1 First Amendment to Credit Agreement dated as of April 21, 2009, among Varistar Corporation (Varistar), the Banks party thereto and U.S. Bank National Association, as Agent, amending the Amended and Restated Credit Agreement dated as of December 23, 2008, among Varistar, the Banks named therein, U.S. Bank National Association, as Agent and as Lead Arranger, and Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on April 24, 2009)

4.2 First Amendment to Credit Agreement dated as of April 21, 2009, among Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company) (OTPC), the Banks party thereto and U.S. Bank National Association, as Agent, amending the Credit Agreement dated as of July 30, 2008, among OTPC, the Banks named therein, Bank of America, N.A., as Syndication Agent, U.S. Bank National Association, as Agent, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, and Merrill

Lynch Bank USA (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on April 24, 2009)

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4.3 Term Loan Agreement, dated as of May 22, 2009, among OTPC, JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on May 29, 2009)

4.4 Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001, among Otter Tail Corporation (now known as Otter Tail Power Company) and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)

4.5 Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007, among Otter Tail Corporation (now known as Otter Tail Power Company) and each of the holders of notes party thereto (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)

4.6 Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007, between Otter Tail Corporation (now known as Otter Tail Power Company) and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)

4.7 First Supplemental Indenture, dated as of July 1, 2009, between Otter Tail Corporation and U.S. Bank National Association, as Trustee, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between Otter Tail Corporation (now known as Otter Tail Power Company) and U.S. Bank National Association (formerly First Trust National Association), as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)

10.1 Standstill Agreement, dated July 1, 2009, by and between Otter Tail Corporation and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer
(Chief Financial Officer/Authorized Officer)

Dated: August 7, 2009

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EXHIBIT INDEX

Exhibit Number	Description
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4.2	First Amendment to Credit Agreement dated as of April 21, 2009, among Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company) (OTPC), the Banks party thereto and U.S. Bank National Association, as Agent, amending the Credit Agreement dated as of July 30, 2008, among OTPC, the Banks named therein, Bank of America, N.A., as Syndication Agent, U.S. Bank National Association, as Agent, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, and Merrill Lynch Bank USA (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on April 24, 2009)
4.3	Term Loan Agreement, dated as of May 22, 2009, among OTPC, JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on May 29, 2009)
4.4	Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001, among Otter Tail Corporation (now known as Otter Tail Power Company) and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)
4.5	Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007, among Otter Tail Corporation (now known as Otter Tail Power Company) and each of the holders of notes party thereto (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)

4.6	Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007, between Otter Tail Corporation (now known as Otter Tail Power Company) and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)
4.7	First Supplemental Indenture, dated as of July 1, 2009, between Otter Tail Corporation and U.S. Bank National Association, as Trustee, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between Otter Tail Corporation (now known as Otter Tail Power Company) and U.S. Bank National Association (formerly First Trust National Association), as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)

Exhibit Number	Description
10.1	Standstill Agreement, dated July 1, 2009, by and between Otter Tail Corporation and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.