

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)**

**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**

**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  NO

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).

YES  NO

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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)**

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Consolidated Balance Sheets**

(not audited)

**-Assets-**

	<b>June 30, 2009</b>	<b>December 31, 2008</b>
	(Thousands of dollars)	
<b>Current Assets</b>		
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
<b>Total Current Assets</b>	<b>321,331</b>	<b>393,011</b>
<b>Investments</b>	8,634	7,542
<b>Other Assets</b>	88,249	22,615
<b>Goodwill</b>	106,778	106,778
<b>Other Intangibles Net</b>	34,637	35,441
<b>Deferred Debits</b>		
Unamortized Debt Expense and Reacquisition Premiums	9,598	7,247
Regulatory Assets and Other Deferred Debits	81,336	82,384
<b>Total Deferred Debits</b>	<b>90,934</b>	<b>89,631</b>
<b>Plant</b>		
Electric Plant in Service	1,210,035	1,205,647
Nonelectric Operations	343,358	321,032
<b>Total Plant</b>	<b>1,553,393</b>	<b>1,526,679</b>
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
<b>Net Plant</b>	<b>1,060,175</b>	<b>1,037,569</b>

<b>Total</b>	\$ 1,710,738	\$ 1,692,587
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See accompanying notes to consolidated financial statements

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

	<b>June 30, 2009</b>	<b>December 31, 2008</b>
	(Thousands of dollars)	
<b>Current Liabilities</b>		
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
<b>Total Current Liabilities</b>	<b>247,915</b>	<b>304,744</b>
<b>Pensions Benefit Liability</b>	<b>82,882</b>	<b>80,912</b>
<b>Other Postretirement Benefits Liability</b>	<b>33,464</b>	<b>32,621</b>
<b>Other Noncurrent Liabilities</b>	<b>20,095</b>	<b>19,391</b>
<b>Commitments (note 9)</b>		
<b>Deferred Credits</b>		
Deferred Income Taxes	132,923	123,086
Deferred Tax Credits	33,212	34,288
Regulatory Liabilities	65,801	64,684
Other	427	397
<b>Total Deferred Credits</b>	<b>232,363</b>	<b>222,455</b>
<b>Capitalization</b>		
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

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Accumulated Other Comprehensive Loss	(2,286)	(3,000)
<b>Total Common Equity</b>	665,464	676,018
<b>Total Capitalization</b>	1,094,019	1,032,464
<b>Total</b>	\$ 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)

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

<b>Dividends Per Common Share</b>	\$ 0.2975	\$ 0.2975	\$ 0.5950	\$ 0.5950
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See accompanying notes to consolidated financial statements

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

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2009</b>	<b>2008</b>
	(Thousands of dollars)	
<b>Cash Flows from Operating Activities</b>		
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
<b>Net Cash Provided by Operating Activities</b>	<b>90,305</b>	<b>34,940</b>
<b>Cash Flows from Investing Activities</b>		
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)
<b>Net Cash Used in Investing Activities</b>	<b>(120,050)</b>	<b>(156,318)</b>
<b>Cash Flows from Financing Activities</b>		
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)

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

See accompanying notes to consolidated financial statements

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**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:

<i>(in thousands)</i>	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:

<i>(in thousands)</i>	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

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\$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

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

**Table of Contents****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 hierarchical 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:

<i>(in thousands)</i>	Level 1	Level 2	Level 3	Total
<b>Assets:</b>				
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
<b>Total Assets</b>	<b>\$6,944</b>	<b>\$23,134</b>	<b>\$</b>	<b>\$30,078</b>
<b>Liabilities:</b>				
Forward Energy Contracts	\$	\$ 3,727	\$	\$ 3,727
Forward Foreign Currency Exchange Contracts	41			41
Asset Retirement Obligations			3,438	3,438
<b>Total Liabilities</b>	<b>\$ 41</b>	<b>\$ 3,727</b>	<b>\$ 3,438</b>	<b>\$ 7,206</b>
<b>Net Assets (Liabilities)</b>	<b>\$6,903</b>	<b>\$19,407</b>	<b>\$(3,438)</b>	<b>\$22,872</b>

**Inventories**

Inventories consist of the following:



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<i>(in thousands)</i>	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

**Table of Contents****Other Intangible Assets**

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
<b>June 30, 2009</b> (in thousands)				
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	
<b>December 31, 2008</b> (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

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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

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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.

**Table of Contents****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		Six Months Ended	
	June 30,		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**

<i>(in thousands)</i>	Three Months Ended June 30,		Six Months Ended June 30,	
	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**

<i>(in thousands)</i>	Three months ended June 30,		Six months ended June 30,	
	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**

<i>(in thousands)</i>	Three months ended June 30,		Six months ended June 30,	
	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)

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

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**Table of Contents****Earnings Available for Common Shares**

<i>(in thousands)</i>	Three months ended		Six months ended	
	2009	2008	2009	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**

<i>(in thousands)</i>	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

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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.

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

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

In an order issued on August 15, 2008, the MPUC approved the electric utility's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the electric utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment (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.

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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.

**Table of Contents****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.

**Table of Contents****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:

<i>(in thousands)</i>	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
<b>Total Regulatory Assets</b>	<b>\$85,096</b>	<b>\$94,725</b>
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
<b>Total Regulatory Liabilities</b>	<b>\$65,801</b>	<b>\$64,684</b>
<b>Net Regulatory Asset Position</b>	<b>\$19,295</b>	<b>\$30,041</b>

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:

<i>(in thousands)</i>	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)

<i>(in thousands)</i>	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.

**Table of Contents****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:

<i>(in thousands)</i>	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