OTTER TAIL CORP
Form 10-Q
November 07, 2008

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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 September 30, 2008

OR

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

For the transition period from __________ to __________

Commission file number 0-368

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

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

866-410-8780
(Registrant s telephone number, including area code)

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

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

Indicate by check mark whether the registrant 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:

October 31, 2008 35,384,620 Common Shares ($5 par value)

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 17,862	$ 39,824
Accounts Receivable:		
Trade Net	171,681	151,446
Other	22,636	14,934
Inventories	111,042	97,214
Deferred Income Taxes	6,904	7,200
Accrued Utility and Cost-of-Energy Revenues	14,207	32,501
Costs and Estimated Earnings in Excess of Billings	60,616	42,234
Other	23,953	15,299
Total Current Assets	428,901	400,652
Investments	8,120	10,057
Other Assets	24,108	24,500
Goodwill	106,778	99,242
Other Intangibles Net	35,977	20,456
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,784	6,986
Regulatory Assets and Other Deferred Debits	41,024	38,837
Total Deferred Debits	47,808	45,823
Plant		
Electric Plant in Service	1,066,957	1,028,917
Nonelectric Operations	306,181	257,590
Total Plant	1,373,138	1,286,507
Less Accumulated Depreciation and Amortization	538,693	506,744
Plant Net of Accumulated Depreciation and Amortization	834,445	779,763
Construction Work in Progress	127,937	74,261
Net Plant	962,382	854,024
Total	$ 1,614,074	$ 1,454,754

See accompanying notes to consolidated financial statements

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

	September 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 111,955	$ 95,000
Current Maturities of Long-Term Debt	3,389	3,004
Accounts Payable	128,547	141,390
Accrued Salaries and Wages	27,507	29,283
Accrued Taxes	10,248	11,409
Other Accrued Liabilities	14,284	13,873
Total Current Liabilities	295,930	293,959
Pensions Benefit Liability	39,537	39,429
Other Postretirement Benefits Liability	31,378	30,488
Other Noncurrent Liabilities	21,157	23,228
Deferred Credits		
Deferred Income Taxes	111,256	105,813
Deferred Tax Credits	17,527	16,761
Regulatory Liabilities	64,066	62,705
Other	330	275
Total Deferred Credits	193,179	185,554
Capitalization		
Long-Term Debt, Net of Current Maturities	340,667	342,694
Class B Stock Options of Subsidiary	1,255	1,255
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2008 and 2007 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 2008 35,384,470 and 2007 29,849,789	176,922	149,249
Premium on Common Shares	240,996	108,885
Retained Earnings	257,327	263,332
Accumulated Other Comprehensive Income	226	1,181
Total Common Equity	675,471	522,647
Total Capitalization	1,032,893	882,096

Total	$ 1,614,074	$ 1,454,754

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating Revenues				
Electric	$ 82,821	$ 72,052	$ 248,904	$ 232,403
Nonelectric	270,098	230,183	727,852	676,797
Total Operating Revenues	352,919	302,235	976,756	909,200
Operating Expenses				
Production Fuel Electric	18,732	16,994	53,444	47,496
Purchased Power Electric System Use	10,456	6,499	39,598	43,531
Electric Operation and Maintenance Expenses	33,091	27,212	87,591	80,738
Cost of Goods Sold Nonelectric (depreciation included below)	213,999	179,868	583,457	521,500
Other Nonelectric Expenses	37,222	30,211	108,211	92,346
Plant Closure Costs	883		2,295	
Depreciation and Amortization	16,563	13,366	47,600	39,406
Property Taxes Electric	2,227	2,538	7,414	7,591
Total Operating Expenses	333,173	276,688	929,610	832,608
Operating Income	19,746	25,547	47,146	76,592
Other Income	1,157	619	2,745	1,232
Interest Charges	7,269	4,927	21,023	14,821
Income Before Income Taxes	13,634	21,239	28,868	63,003
Income Taxes	4,003	7,907	7,490	23,160
Net Income	9,631	13,332	21,378	39,843
Preferred Dividend Requirements	184	184	552	552
Earnings Available for Common Shares	$ 9,447	$ 13,148	$ 20,826	$ 39,291
Earnings Per Common Share:				
Basic	$ 0.31	$ 0.44	$ 0.69	$ 1.33
Diluted	$ 0.31	$ 0.44	$ 0.69	$ 1.31
Average Number of Common Shares Outstanding:				

Basic		30,513,578		29,745,600		30,108,381		29,644,866
Diluted		30,817,013		29,995,660		30,398,235		29,887,510
Dividends Per Common Share	$	0.2975	$	0.2925	$	0.8925	$	0.8775

See accompanying notes to consolidated financial statements

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

	Nine months ended September 30, 2008	2007
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 21,378	$ 39,843
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	47,600	39,406
Deferred Tax Credits	(1,180)	(852)
Deferred Income Taxes	9,123	2,706
Change in Deferred Debits and Other Assets	(2,162)	(484)
Discretionary Contribution to Pension Plan	(2,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	1,795	6,116
Allowance for Equity (Other) Funds Used During Construction	(1,712)	
Change in Derivatives Net of Regulatory Deferral	(337)	(163)
Stock Compensation Expense	2,885	1,592
Other Net	580	(469)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(24,314)	(26,883)
Change in Inventories	(9,054)	7,779
Change in Other Current Assets	(8,165)	3,562
Change in Payables and Other Current Liabilities	4,997	(15,194)
Change in Interest and Income Taxes Payable	810	4,382
Net Cash Provided by Operating Activities	40,244	57,341
Cash Flows from Investing Activities		
Capital Expenditures	(172,237)	(99,433)
Proceeds from Disposal of Noncurrent Assets	7,446	8,297
Acquisitions Net of Cash Acquired	(41,674)	(6,750)
Increases in Other Investments	(393)	(5,824)
Net Cash Used in Investing Activities	(206,858)	(103,710)
Cash Flows from Financing Activities		
Net Short-Term Borrowings	16,955	39,881
Proceeds from Issuance of Common Stock	162,961	7,633
Common Stock Issuance Expenses	(6,136)	
Payments for Retirement of Common Stock	(91)	(305)
Proceeds from Issuance of Long-Term Debt	1,140	25,128
Short-Term and Long-Term Debt Issuance Expenses	(527)	(328)
Payments for Retirement of Long-Term Debt	(2,691)	(2,445)
Dividends Paid	(27,382)	(26,601)

Net Cash Provided by Financing Activities	144,229	42,963
Effect of Foreign Exchange Rate Fluctuations on Cash	423	(2,681)
Net Change in Cash and Cash Equivalents	(21,962)	(6,087)
Cash and Cash Equivalents at Beginning of Period	39,824	6,791
Cash and Cash Equivalents at End of Period	$ 17,862	$ 704

See accompanying notes to consolidated financial statements

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OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated results of operations for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2007, 2006 and 2005 included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2007. Because of seasonal and other factors, the earnings for the three-month and nine-month periods ended September 30, 2008 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 on the notes included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

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 34.6% for the three months ended September 30, 2008 compared with 33.3% for the three months ended September 30, 2007 and 32.3% for the nine months ended September 30, 2008 compared with 29.5% for the nine months ended September 30, 2007. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours 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 a 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)	September 30, 2008	December 31, 2007
Costs Incurred on Uncompleted Contracts	$ 518,863	$ 286,358
Less Billings to Date	(528,496)	(292,692)
Plus Estimated Earnings Recognized	63,801	38,275
	$ 54,168	$ 31,941

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)	September 30, 2008	December 31, 2007
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 60,616	$ 42,234
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(6,448)	(10,293)
	$ 54,168	$ 31,941

Sales of Receivables

In March 2008, DMI Industries, Inc. (DMI), the Company s wind tower manufacturer, entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $90.9 million have been sold in 2008. Discounts of $0.5 million for the nine months ended September 30, 2008 were charged to operating expenses in the consolidated statements of income. In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Marketing and Sales Incentive Costs

ShoreMaster, Inc. (ShoreMaster), the Company s waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with Emerging Issues Task Force Issue No. 01-9, *Accounting for Consideration Given by a Vendor to a Customer (Including a Reseller of a Vendor s Products)*. The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs of $98,000 for the three months ended September 30, 2008 and $338,000 for the nine months ended September 30, 2008 were charged to revenue.

Supplemental Disclosures of Cash Flow Information

(in thousands)	Nine Months Ended September 30, 2008	2007
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$(21,117)	$ 1,631
Cash Paid During the Period for:		
Interest (net of amount capitalized)	$ 19,925	$11,899
Income Taxes	$ 1,779	$18,896

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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, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights.

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 September 30, 2008:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market and Mutual Funds and Cash	$ 1,049			$ 1,049
Cash Surrender Value of Life Insurance Policies		$ 9,211		9,211
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,235		10,235
Forward Energy Contracts		4,922		4,922
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,707			3,707
U.S. Government Debt Securities	1,323			1,323
Total Assets	$ 6,079	$ 24,368		$ 30,447
Liabilities:				
Forward Energy Contracts		$ 3,427		$ 3,427
Forward Foreign Currency Exchange Contracts	$ 114			114
Total Liabilities	$ 114	$ 3,427		$ 3,541
Net Assets	$ 5,965	$ 20,941		$ 26,906

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Inventories

Inventories consist of the following:

(in thousands)	September 30, 2008	December 31, 2007
Finished Goods	$ 45,492	$ 38,952
Work in Process	11,044	5,218
Raw Material, Fuel and Supplies	54,506	53,044
	$ 111,042	$ 97,214

Goodwill and Other Intangible Assets

As a result of the acquisition of Miller Welding & Iron Works, Inc. (Miller Welding) by BTD Manufacturing, Inc. (BTD) in May 2008, Goodwill increased $7,986,000, Covenants Not to Compete increased by $100,000, Customer Relationships increased by $16,100,000 and Brand/Trade Name increased by $400,000. In the second quarter of 2008, ShoreMaster eliminated $282,000 of fully amortized Covenants Not to Compete. As a result of the sale of certain imaging assets and routes in the Health Services segment in the third quarter of 2008, Goodwill was reduced by $450,000 and $200,000 of fully amortized Covenants Not to Compete were eliminated.

The following table summarizes the components of the Company s other intangible assets at September 30, 2008 and December 31, 2007:

	September 30, 2008			December 31, 2007		
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets:						
Covenants Not to Compete	$ 2,256	$ 1,817	$ 439	$ 2,637	$ 2,113	$ 524
Customer Relationships	26,946	2,130	24,816	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,785	1,944	841	2,785	1,775	1,010
Total	$ 31,987	$ 5,891	$ 26,096	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:						
Brand/Trade Name	$ 9,881	$	$ 9,881	$ 9,512	$	$ 9,512

Intangible assets with finite lives are being amortized on a straight-line basis over average lives ranging from 3 to 25 years. The amortization expense for these intangible assets was $1,023,000 for the nine months ended September 30, 2008 compared to $985,000 for the nine months ended September 30, 2007. The estimated annual amortization expense for these intangible assets for the next five years is $1,448,000 for 2008, $1,633,000 for 2009, $1,461,000 for 2010, $1,332,000 for 2011 and $1,312,000 for 2012.

Comprehensive Income

	Three Months Ended	Nine Months Ended

(in thousands)	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
Net Income	$ 9,631	$ 13,332	$ 21,378	$ 39,843
Other Comprehensive Income (net-of-tax)				
Foreign Currency Translation (Loss) Gain	(579)	571	(954)	1,617
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	37	43	117	131
Unrealized (Loss) Gain on Available-For-Sale Securities	(83)	5	(118)	(12)
Total Other Comprehensive (Loss) Income	(625)	619	(955)	1,736
Total Comprehensive Income	$ 9,006	$ 13,951	$ 20,423	$ 41,579

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New Accounting Standards

SFAS No. 157, ***Fair Value Measurements,*** was issued by the Financial Accounting Standards Board (FASB) in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Adoption of SFAS No. 157 will result in additional footnote disclosures related to the use of fair value measurements in the areas of investments, derivatives, asset retirement obligations, goodwill and asset impairment evaluations, financial instruments and acquisitions. The Company adopted SFAS No. 157 on January 1, 2008 and required disclosures are included in this report on Form 10-Q.

SFAS No. 159, ***The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115,*** was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company adopted SFAS No. 159 on January 1, 2008. The adoption of this pronouncement had no effect on the Company s consolidated financial statements because the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 January 1, 2009 for the Company. 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.

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 January 1, 2009 for the Company. Adoption of SFAS No. 161 will result in additional footnote disclosures related to the Company s use of derivative instruments but those additional disclosures will not be extensive because the derivative instruments currently held by the Company are not designated as hedging instruments under this statement.

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2. Business Combination and Segment Information

Acquisition

On May 1, 2008 BTD acquired the assets of Miller Welding of Washington, Illinois for $41.7 million in cash. Miller Welding, a custom job shop fabricator and finisher, recorded $26 million in revenue in 2007. Miller Welding manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver. This acquisition will provide opportunities for growth in new and existing markets for both BTD and Miller Welding, and complementing production capabilities will expand the scope and capacity of services offered by both companies.

Below is condensed balance sheet information, at the date of the business combination, disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category of Miller Welding:

(in thousands)	
Assets	
Current assets	$ 8,855
Goodwill	7,986
Other Intangible Assets	16,600
Fixed Assets	8,994
Total Assets	$ 42,435
Liabilities	
Current Liabilities	$ 761
Noncurrent Liabilities	
Total Liabilities	$ 761
Cash Paid	$ 41,674

Other Intangible Assets related to the Miller Welding acquisition include $16,100,000 for Customer Relationships being amortized over 20 years, $400,000 for a Nonamortizable Trade Name and a $100,000 Covenant Not to Compete being amortized over three years.

Segment Information

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

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

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

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

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

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

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

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

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

The Company has a customer within the Manufacturing segment that accounted for approximately 10.2% of the Company s consolidated revenues for the nine months ended September 30, 2008. No other single external customer accounts for 10% or more of the Company s revenues. Substantially all of the Company s long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
United States of America	97.9%	97.8%	97.1%	96.7%
Canada	1.1%	0.9%	1.3%	1.4%
All other countries (none greater than 1%)	1.0%	1.3%	1.6%	1.9%

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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 nine-month periods ended September 30, 2008 and 2007 and total assets by business segment as of September 30, 2008 and December 31, 2007 are presented in the following tables:

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 82,883	$ 72,110	$ 249,139	$ 232,662
Plastics	36,690	36,975	99,685	114,319
Manufacturing	127,778	95,330	345,715	286,341
Health Services	31,139	31,360	91,144	96,775
Food Ingredient Processing	15,333	15,714	47,144	53,612
Other Business Operations	59,650	51,231	145,840	126,964
Corporate Revenues and Intersegment Eliminations	(554)	(485)	(1,911)	(1,473)
Total	$ 352,919	$ 302,235	$ 976,756	$ 909,200

Interest Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 3,158	$ 2,465	$ 9,272	$ 7,356
Plastics	369	242	838	750
Manufacturing	2,659	2,141	7,035	6,125
Health Services	176	223	531	683
Food Ingredient Processing	46	34	87	167
Other Business Operations	331	315	933	757
Corporate and Intersegment Eliminations	530	(493)	2,327	(1,017)
Total	$ 7,269	$ 4,927	$ 21,023	$ 14,821

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 1,863	$ 3,595	$ 8,017	$ 9,500
Plastics	1,088	941	1,942	5,081
Manufacturing	288	2,359	303	7,564
Health Services	208	84	(218)	1,306
Food Ingredient Processing	(717)	942	497	1,891
Other Business Operations	2,908	935	2,291	1,752
Corporate	(1,635)	(949)	(5,342)	(3,934)

Total	$ 4,003	$ 7,907	$ 7,490	$ 23,160

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Earnings Available for Common Shares

(in thousands)	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Electric	$ 6,335	$ 6,309	$ 21,993	$ 16,939
Plastics	1,641	1,384	2,913	7,610
Manufacturing	380	3,477	1,160	11,351
Health Services	254	53	(525)	1,709
Food Ingredient Processing	(1,074)	993	734	2,985
Other Business Operations	4,341	1,361	3,370	2,595
Corporate	(2,430)	(429)	(8,819)	(3,898)
Total	$ 9,447	$ 13,148	$ 20,826	$ 39,291

Total Assets

(in thousands)	September 30, 2008	December 31, 2007
Electric	$ 896,355	$ 813,565
Plastics	91,669	77,971
Manufacturing	340,178	274,780
Health Services	63,533	64,824
Food Ingredient Processing	92,978	91,966
Other Business Operations	84,546	72,258
Corporate	44,815	59,390
Total	$ 1,614,074	$ 1,454,754

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 approximately 2.9%, compared with the originally requested increase of approximately 6.7%. An interim rate increase of 5.4% went into effect on November 30, 2007. The electric utility will refund Minnesota customers the difference between interim rates and final rates, with interest. The refund will commence within 120 days after the final order is no longer subject to appeal. After the refund is commenced, it must be completed within 90 days. Amounts refundable totaling $3.1 million have been recorded as a liability on the Company s consolidated balance sheet as of September 30, 2008.The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. The electric utility disagreed with certain aspects of the MPUC decision and requested reconsideration of those items. Other participants requested reconsideration of other aspects of the decision.

On October 8, 2008 the MPUC rendered decisions on the five issues raised in these requests for reconsideration. The MPUC granted reconsideration on two issues but only changed its decision on the treatment of non-asset-based margins. Non-asset-based margins come from the unregulated side of the electric utility s business and, therefore, costs associated with non-asset-based sales activities should be excluded from recovery in retail rates. This can be accomplished by either assigning an amount of electric utility costs to the unregulated activity, thus removing those costs from retail rates, or by sharing non-asset-based margins with retail customers. The original MPUC decision reflected both practices. As a result of the MPUC decision on reconsideration, the electric utility will assign an amount of utility costs to the unregulated activity but will not be required to share non-asset-based margins with retail customers. The original MPUC decision would have required the electric utility to share 10% of actual non-asset-based margins through a fuel clause adjustment mechanism, rather than as a reduction to revenue requirements and base rates. Therefore, this decision did not change the amount of the base rate increase granted on August 1, 2008. The MPUC s written order dated August 1, 2008, reflects the final approved revenue increase of $3.8 million, or about 2.9%. The final revenue increase is 44% of the increase originally requested by the electric utility.

The electric utility expects to implement final rates in January 2009 and to begin interim rate refunds in February 2009. The electric utility reversed and 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 three years under new rates as ordered by the MPUC.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need 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. The MPUC is expected to decide if the lines meet regulatory need requirements by early 2009. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. The MPUC would determine routes for the new lines in separate proceedings. After regulatory need is established and routing decisions are completed (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading these projects, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company is directly involved in two of these three projects and serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kv line which has an expected in-service date of 2012-2013.

The electric utility filed a Certificate of Need for the fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (OES) staff completed briefing papers regarding the Bemidji/Grand Rapids route permit application. The OES staff recommended to the MPUC that: (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 OES staff recommendation. The MPUC agreed that the Certificate of Need and route permit applications were complete. The commissioners asked the CapX 2020 utilities to add a section to the Certificate of Need application addressing how the new Minnesota Conservation Improvement Programs (CIP) statutes will affect the need for the project. Because no one has intervened in the Certificate of Need proceeding, the MPUC will handle the Certificate of Need application as an uncontested case. The MPUC is expected to determine if there is a need for this line in the fourth quarter of 2008 and, if appropriate, issue the route permit in 2009.

Renewable Energy Standards, Conservation and Renewable Resource 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. The electric utility s compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to 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 in an integrated resource plan or Certificate of Need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

In an order issued on August 15, 2008, the MPUC approved the electric utility s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the electric utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment of 0.19 cents per kilowatt-hour (kwh) was included on Minnesota customers electric service statements beginning in September 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The Company s June 30, 2008 consolidated balance sheet included a regulatory asset of $1.5 million for deferred recognition of the Minnesota portion of renewable resource costs. As a result of the MPUC approval, the electric utility reversed and expensed the $1.5 million of deferred costs in the third quarter of 2008 and has recognized a regulatory asset of $2.7 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of September 30, 2008.

The electric utility has requested that a decision on its 2009 Rider Adjustment filing be delayed until January 1, 2009 with an expected implementation date of April 1, 2009, so that investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center, scheduled to be commercially operational by January 2009, can be considered for inclusion in the 2009 Rider Adjustment.

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 to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility s retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility s last general rate case. The electric utility plans to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in the fourth quarter of 2008.

North Dakota

Renewable Resource Cost Recovery Rider On May 21, 2008 the North Dakota Public Service Commission (NDPSC) approved the electric utility s request for a Renewable Resource Cost Recovery Rider to enable the electric utility to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The Renewable Resource Cost Recovery Rider Adjustment of 0.193 cents per kwh was included on North Dakota customers electric service statements beginning in June 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The electric utility has included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center scheduled to be commercially operational by January 2009 in its 2009 annual request to the NDPSC to increase the amount of the Renewable Resource Cost Recovery Rider Adjustment.

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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, the electric utility has 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 September 30, 2008 consolidated balance sheet includes a regulatory asset of $1.7 million for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but that had not been billed to North Dakota customers as of September 30, 2008.

North Dakota legislation also provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The electric utility plans to request recovery of such costs under the automatic adjustment mechanism in the fourth quarter of 2008.

Federal

Transmission Practices Audit The Federal Energy Regulatory Commission s (FERC) Office of Enforcement, formerly referred to as the Division of Operation Audits of the Office of Market Oversight and Investigations, commenced an audit of the electric utility s transmission practices in 2005 for the period January 1, 2003 through August 31, 2005. The purpose of the audit was to determine whether the electric utility s transmission practices were in compliance with the FERC s applicable rules, regulations and tariff requirements and whether the implementation of the electric utility s waivers from the requirements of Order No. 889 and Order No. 2004 appropriately restricted access to transmission information that would benefit the electric utility s off-system sales. FERC staff identified two of the electric utility s transmission practices that it believed were out of compliance. The electric utility believes its actions were in compliance with the MISO tariff but rather than litigate, it entered into a Stipulated Settlement Agreement with FERC staff resolving all issues related to the audit. The FERC approved the settlement agreement on May 29, 2008.

FERC Order (IN08-6-000), issued May 29, 2008, resolves alleged network transmission service violations by the electric utility of the Open Access Transmission and Energy Markets Tariff (OATT) of the MISO. The electric utility agreed to pay $547,000 plus interest of $141,000 to the Low Income Home Energy Assistance Program administered by the three states served by the electric utility. This amount represents profits earned by the electric utility on transactions FERC staff believes incorrectly utilized network transmission service under MISO s OATT. Enforcement staff did not seek to impose a compliance monitoring plan on the electric utility because the MISO s Day 2 market is now operational and its member utilities no longer schedule transmission within the system.

Big Stone II Project

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

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In the fourth quarter of 2005, the participating utilities filed applications with the MPUC for a transmission Certificate of Need and a Route Permit for the Minnesota portion of the Big Stone II transmission line. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs recommended potential conditions in an August 31, 2007 proposed settlement agreement with the Minnesota Department of Commerce that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008.

On May 9, 2008 the ALJs issued a report reversing their previous recommendation recommending that the MPUC deny the petition for a Certificate of Need and related route permits for the proposed transmission lines. On May 19, 2008 the five Big Stone II participating utilities filed exceptions to the ALJs Report and Recommendation with the MPUC. The MPUC heard oral arguments on the Big Stone II transmission Certificate of Need application on June 3, 2008. The MPUC decision on these matters was expected in June 2008, but in a 3-2 vote on June 5, 2008, the MPUC deferred its decision on the Big Stone II transmission Certificate of Need for purposes of obtaining additional expert opinion on three issues: carbon regulation costs, construction costs and fuel costs.

On October 22, 2008, the MPUC made public the report of the expert, Boston Pacific Company, Inc. (Boston Pacific). In addition to minor differences in estimated costs of construction and fuel, Boston Pacific recommended a significant increase in the range of carbon regulation costs utilized in the Big Stone II utilities modeling. The Big Stone II utilities used a carbon dioxide emission cost range of $4 to $30 per ton adopted by the MPUC for utilities to use in resource planning dockets. The Boston Pacific report recommends modeling a range of carbon regulation costs of up to $60 per ton and states that the modeling should apply the costs as a tax, given the uncertainty of cost estimates associated with potential cap and trade regimes.

Hearings on the Boston Pacific report are scheduled to be held in November 2008 before a Minnesota ALJ. The ALJ s summary report is expected in late December 2008 and MPUC deliberations are expected to begin in January 2009. The electric utility currently expects a decision on the transmission Certificate of Need application in the first quarter of 2009.

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 also 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. The electric utility and Montana-Dakota Utilities Co. also made a filing for an advance determination of prudence on Big Stone II with the NDPSC, and on August 27, 2008 the NDPSC determined that the electric utility s participation in Big Stone II was prudent in a range of 121.8 to 130 megawatts. In addition, the Big Stone II participating utilities have filed a contested case proceeding with the South Dakota Board of Minerals and Environment to acquire air permits for Big Stone II. A decision by the South Dakota Board of Minerals and Environment is expected in 2008. 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. The electric utility is assessing ways in which to address this potential near-term generation shortfall.

As of September 30, 2008 the electric utility has capitalized $10.8 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. 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.

Holding Company Reorganization

The Company s Board of Directors has authorized a holding company reorganization of the Company s regulated utility business. Following the completion of the holding company reorganization, Otter Tail Power Company, which is currently operated as a division of Otter Tail Corporation, will be operated as a wholly owned subsidiary of the new parent holding company to be named Otter Tail Corporation. In connection with the reorganization, each outstanding Otter Tail Corporation common share will be automatically converted into one common share of the new holding company, and each outstanding Otter Tail Corporation cumulative preferred share will be automatically converted into one cumulative preferred share of the new holding company having the same terms. The holding company reorganization is subject to approval by Minnesota, North Dakota and South Dakota regulatory agencies and by the FERC, consents from various third parties and certain other conditions. In an order issued on August 18, 2008, the FERC authorized the reorganization subject to certain conditions specified in the order. In an order issued on October 10, 2008, the NDPSC approved the Company s application to form a holding company. In a meeting held on October 30, 2008, the South Dakota Public Utilities Commission (SDPUC) approved the Company s application to form a new holding company. A hearing in Minnesota is not expected until December 2008 or later.

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)		September 30, 2008		December 31, 2007
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$	25,217	$	26,933
Deferred Income Taxes		8,012		8,733
Accrued Cost-of-Energy Revenue		4,286		19,452
Debt Reacquisition Premiums		3,446		3,745
Minnesota Renewable Resource Rider Accrued Revenues		2,741		
North Dakota Renewable Resource Rider Accrued Revenues		1,662		
Minnesota General Rate Case Recoverable Expenses		1,457		
MISO Schedule 16 and 17 Deferred Administrative Costs ND		756		576
MISO Schedule 16 and 17 Deferred Administrative Costs MN		595		855
Accumulated ARO Accretion/Depreciation Adjustment		502		345
Deferred Marked-to-Market Losses		271		771
Plant Acquisition Costs		74		107
Deferred Conservation Improvement Program (Revenues) Costs		(263)		518
Total Regulatory Assets	$	48,756	$	62,035
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs	$	58,894	$	57,787
Deferred Income Taxes		4,349		4,502
Deferred Marked-to-Market Gains		682		271
Gain on Sale of Division Office Building		141		145

Total Regulatory Liabilities	$	64,066	$	62,705
Net Regulatory Liability Position	$	15,310	$	670

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The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs 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,* adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

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

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 23 months.

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 24 years.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve Minnesota customers since January 1, 2008 that have not been billed to Minnesota customers as of September 30, 2008. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from October 2008 through December 2009.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve North Dakota customers since January 1, 2008 that have not been billed to North Dakota customers as of September 30, 2008. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from October 2008 through December 2009.

Minnesota General Rate Case Recoverable Expenses will be recovered over a 36-month period from the time revised rates established by the recent Minnesota general rate case go into effect.

MISO Schedule 16 and 17 Deferred Administrative Costs ND were excluded from recovery through the Fuel Clause Adjustment (FCA) in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility s general rate case filed in North Dakota in November 2008.

MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 26 months.

The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred.

All Deferred Marked-to-Market Losses and Gains recorded as of September 30, 2008 are related to forward purchases of energy scheduled for delivery prior to March 2009.

Plant Acquisition Costs will be amortized over the next 20 months.

Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 21 months.

The remaining regulatory liabilities will be paid to electric customers over the next 30 years.

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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

As of September 30, 2008 the electric utility had recognized, on a pretax basis, $1,084,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility s power services personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in SFAS No. 157.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on the Company s consolidated balance sheet as of September 30, 2008 and the change in the Company s consolidated balance sheet position from December 31, 2007 to September 30, 2008:

(in thousands)		September 30, 2008
Current Asset Marked-to-Market Gain	$	4,922
Regulatory Asset Deferred Marked-to-Market Loss		271
Total Assets		5,193
Current Liability Marked-to-Market Loss		(3,427)
Regulatory Liability Deferred Marked-to-Market Gain		(682)
Total Liabilities		(4,109)
Net Fair Value of Marked-to-Market Energy Contracts	$	1,084

(in thousands)		Year-to-Date September 30, 2008
Fair Value at Beginning of Year	$	632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008		(204)
Changes in Fair Value of Contracts Entered into in 2007		570
Net Fair Value of Contracts Entered into in 2007 at End of Period		998
Changes in Fair Value of Open Contracts Entered into in 2008		86
Net Fair Value End of Period	$	1,084

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 March 2008 to cover approximately 50% of its monthly expenditures for the last nine months of 2008. Each contract is for the exchange of $400,000 USD for the amount of Canadian dollars stated in each contract, for a total exchange of $3,600,000 USD for $3,695,280 CAD.

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In July 2008, IPH s Canadian subsidiary entered into additional forward contracts for the exchange of U.S. dollars into Canadian dollars to cover approximately 50% of its monthly expenditures for the twelve-month period of August 2008 through July 2009. Each contract is for the exchange of $400,000 USD for the amount of Canadian dollars stated in each contract, for a total exchange of $4,800,000 USD for $5,003,160 CAD. Each of these contracts can be settled incrementally during the month the contract is scheduled for settlement, but for practical reasons and to reduce settlement fees each contract will most likely be settled in one or two exchanges.

These open 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 will not qualify for hedge accounting treatment because the timing of their settlements will not coincide with the payment of specific bills or existing contractual obligations.

The foreign currency exchange forward contracts outstanding as of September 30, 2008 were valued and marked to market on September 30, 2008 based on quoted exchange values of similar contracts that could be purchased on September 30, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative liability of $114,000 as of September 30, 2008 and net mark-to-market losses of $106,000 in 2008. The fair value measurements of these forward energy contracts fall into level 1 of the fair value hierarchy set forth in SFAS No. 157.

6. Common Shares and Earnings Per Share