Otter Tail Corp
Form 10-Q
November 09, 2011

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2011

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 X NO

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

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

Large accelerated filer X

Accelerated filer __

Non-accelerated filer __
(Do not check if a smaller reporting company)

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 X

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

October 31, 2011 – 36,062,023 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)		September 30, 2011		December 31, 2010
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	6,604	$	--
Accounts Receivable:				
Trade—Net		152,761		124,353
Other		16,249		19,399
Inventories		91,114		79,270
Deferred Income Taxes		11,987		11,068
Accrued Utility and Cost-of-Energy Revenues		13,446		16,323
Costs and Estimated Earnings in Excess of Billings		54,309		67,352
Income Taxes Receivable		1,530		4,146
Other		23,627		20,224
Assets of Discontinued Operations		77		93,783
Total Current Assets		371,704		435,918
Investments		11,564		9,708
Other Assets		27,109		27,356
Goodwill		69,742		69,742
Other Intangibles—Net		15,712		16,280
Deferred Debits				
Unamortized Debt Expense		6,763		6,444
Regulatory Assets		111,454		127,766
Total Deferred Debits		118,217		134,210
Plant				
Electric Plant in Service		1,343,080		1,332,974
Nonelectric Operations		368,739		340,167
Construction Work in Progress		67,174		42,031
Total Gross Plant		1,778,993		1,715,172
Less Accumulated Depreciation and Amortization		681,057		637,831
Net Plant		1,097,936		1,077,341
Total Assets	$	1,711,984	$	1,770,555

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)		September 30, 2011		December 31, 2010
LIABILITIES AND EQUITY				
Current Liabilities				
Short-Term Debt	$	39,075	$	79,490
Current Maturities of Long-Term Debt		3,286		604
Accounts Payable		113,966		113,761
Accrued Salaries and Wages		21,682		20,252
Accrued Taxes		10,034		11,957
Derivative Liabilities		16,390		17,991
Other Accrued Liabilities		11,368		9,546
Liabilities of Discontinued Operations		77		23,176
Total Current Liabilities		215,878		276,777
Pensions Benefit Liability		76,237		73,538
Other Postretirement Benefits Liability		43,666		42,372
Other Noncurrent Liabilities		19,813		21,043
Commitments and Contingencies (note 9)				
Deferred Credits				
Deferred Income Taxes		178,308		162,208
Deferred Tax Credits		33,573		44,945
Regulatory Liabilities		69,113		66,416
Other		497		556
Total Deferred Credits		281,491		274,125
Capitalization				
Long-Term Debt, Net of Current Maturities		433,454		434,812
Class B Stock Options of Subsidiary		--		525
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2011 and 2010 – 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, 2011—36,062,023 Shares; 2010—36,002,739 Shares		180,310		180,014
Premium on Common Shares		252,219		251,919
Retained Earnings		196,295		198,443
Accumulated Other Comprehensive (Loss) Income		(2,879)		1,487
Total Common Equity		625,945		631,863
Total Capitalization		1,074,899		1,082,700
Total Liabilities and Equity	$	1,711,984	$	1,770,555

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating Revenues				
Electric	$ 85,117	$ 89,272	$ 254,618	$ 258,130
Nonelectric	230,641	170,474	659,473	495,879
Total Operating Revenues	315,758	259,746	914,091	754,009
Operating Expenses				
Production Fuel - Electric	19,080	18,210	55,737	55,611
Purchased Power - Electric System Use	7,488	10,254	27,759	32,730
Electric Operation and Maintenance Expenses	27,323	27,098	84,718	84,817
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	184,964	138,403	534,503	392,899
Other Nonelectric Expenses	37,163	32,298	97,470	93,527
Asset Impairment Charge	--	--	--	19,740
Depreciation and Amortization	19,937	19,175	58,748	56,404
Property Taxes - Electric	2,601	2,271	7,427	7,222
Total Operating Expenses	298,556	247,709	866,362	742,950
Operating Income	17,202	12,037	47,729	11,059
Other Income	489	704	2,317	1,269
Interest Charges	8,708	9,287	27,346	27,707
Income (Loss) Before Income Taxes – Continuing Operations	8,983	3,454	22,700	(15,379)
Income Tax Expense (Benefit) – Continuing Operations	2,109	(607)	4,194	(6,625)
Net Income (Loss) from Continuing Operations	6,874	4,061	18,506	(8,754)
Discontinued Operations				
Income (Loss) from Discontinued Operations net of income tax (benefit) expense of $(34), $1,225, $(398), and $3,081 for the respective periods	(52)	2,040	(412)	5,354
Gain (Loss) on Disposition of Discontinued Operations net of income tax				

(benefit) expense of $(302), $0, $3,213, and $0 for the respective periods	(454)	--	12,798	--
Net Income (Loss) from Discontinued Operations	(506)	2,040	12,386	5,354
Total Net Income (Loss)	6,368	6,101	30,892	(3,400)
Preferred Dividend Requirement and Other Adjustments	184	187	874	650
Earnings Available for Common Shares	$ 6,184	$ 5,914	$ 30,018	$ (4,050)
Average Number of Common Shares Outstanding—Basic	35,933,003	35,806,453	35,911,993	35,775,418
Average Number of Common Shares Outstanding—Diluted	36,171,555	36,076,421	36,150,545	35,775,418
Basic Earnings Per Common Share:				
Continuing Operations (net of preferred dividend requirement)	$ 0.18	$ 0.11	$ 0.50	$ (0.26)
Discontinued Operations (net of other adjustments)	(0.01)	0.06	0.34	0.15
	$ 0.17	$ 0.17	$ 0.84	$ (0.11)
Diluted Earnings Per Common Share:				
Continuing Operations (net of preferred dividend requirement)	$ 0.18	$ 0.11	$ 0.50	$ (0.26)
Discontinued Operations (net of other adjustments)	(0.01)	0.05	0.33	0.15
	$ 0.17	$ 0.16	$ 0.83	$ (0.11)
Dividends Declared Per Common Share	$ 0.2975	$ 0.2975	$ 0.8925	$ 0.8925
See accompanying notes to consolidated financial statements.				

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

(in thousands)	Nine Months Ended September 30, 2011	2010
Cash Flows from Operating Activities		
Net Income (Loss)	$ 30,892	$ (3,400)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Net Gain from Sale of Discontinued Operations	(12,798)	--
Net Loss (Income) from Discontinued Operations	412	(5,354)
Depreciation and Amortization	58,748	56,404
Asset Impairment Charge	--	19,740
Deferred Tax Credits	(1,834)	(2,037)
Deferred Income Taxes	10,144	17,373
Change in Deferred Debits and Other Assets	11,844	(1,298)
Discretionary Contribution to Pension Fund	--	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	1,742	5,534
Allowance for Equity (Other) Funds Used During Construction	(576)	(8)
Change in Derivatives Net of Regulatory Deferral	(177)	202
Stock Compensation Expense – Equity Awards	1,760	1,973
Other—Net	(301)	(444)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(25,251)	(47,442)
Change in Inventories	(11,845)	87
Change in Other Current Assets	11,038	4,586
Change in Payables and Other Current Liabilities	3,463	1,103
Change in Interest Payable and Income Taxes Receivable/Payable	764	29,886
Net Cash Provided by Continuing Operations	78,025	56,905
Net Cash Provided by Discontinued Operations	2,347	3,970
Net Cash Provided by Operating Activities	80,372	60,875
Cash Flows from Investing Activities		
Capital Expenditures	(71,337)	(61,382)
Proceeds from Disposal of Noncurrent Assets	3,055	2,709
Net Decrease (Increase) in Other Investments	234	(1,669)
Net Cash Used in Investing Activities - Continuing Operations	(68,048)	(60,342)
Net Proceeds from Sale of Discontinued Operations	84,330	--
Net Cash Used in Investing Activities - Discontinued Operations	(6,065)	(1,485)
Net Cash Provided by (Used in) Investing Activities	10,217	(61,827)
Cash Flows from Financing Activities		

Change in Checks Written in Excess of Cash	(10,031)	4,528
Net Short-Term Borrowings	(40,415)	86,388
Proceeds from Issuance of Common Stock	--	549
Proceeds from Issuance of Class B Stock of Subsidiary	--	158
Common Stock Issuance Expenses	--	(142)
Payments for Retirement of Common Stock	(152)	(401)
Payments for Retirement of Class B Stock of Subsidiary	--	(1,017)
Proceeds from Issuance of Long-Term Debt	2,007	95
Short-Term and Long-Term Debt Issuance Expenses	(1,577)	(1,699)
Payments for Retirement of Long-Term Debt	(683)	(59,166)
Dividends Paid and Other Distributions	(33,011)	(32,824)
Net Cash Used in Financing Activities - Continuing Operations	(83,862)	(3,531)
Net Cash Provided by Financing Activities - Discontinued Operations	201	256
Net Cash Used in Financing Activities	(83,661)	(3,275)
Cash and Cash Equivalents at Beginning of Period – Discontinued Operations	--	(609)
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	(324)	(205)
Net Change in Cash and Cash Equivalents	6,604	(5,041)
Cash and Cash Equivalents at Beginning of Period	--	5,041
Cash and Cash Equivalents at End of Period	$ 6,604	$ --
See accompanying notes to consolidated financial statements.		

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the condensed consolidated financial statements for the periods presented. The condensed 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, 2010, 2009 and 2008 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Because of seasonal and other factors, the earnings for the three month and nine month periods ended September 30, 2011 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, 2010.

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 Otter Tail Power Company’s (OTP) forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with the Financial Accounting Standards Board Accounting Standards Codification (ASC). 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 in the Company’s Wind Energy, Manufacturing and Construction segments enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. 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 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. Following are the percentages of the Company’s consolidated revenues recorded under the percentage-of-completion method:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Percentage-of-Completion Revenues	34.9 %	26.3 %	33.5 %	26.5 %

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

(in thousands)	September 30, 2011	December 31, 2010
Costs Incurred on Uncompleted Contracts	$ 525,259	$ 460,125
Less Billings to Date	(507,751)	(430,471)
Plus Estimated Earnings Recognized	26,756	31,231
Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts	$ 44,264	$ 60,885

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, 2011	December 31, 2010
Costs and Estimated Earnings in Excess of Billings	$ 54,309	$ 67,352
Billings in Excess of Costs and Estimated Earnings	(10,045)	(6,467)
Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts	$ 44,264	$ 60,885

Included in Costs and Estimated Earnings in Excess of Billings are the following amounts at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer:

(in thousands)	September 30, 2011	December 31, 2010
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts - DMI	$ 38,843	$ 58,990

These amounts are 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.

Warranty Reserves

The Company establishes reserves for estimated product warranty costs at the time revenue is recognized based on historical warranty experience and additionally for any known product warranty issues. Certain Company products carry one to fifteen year warranties. Although the Company engages in extensive product quality programs and processes, the Company's warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures.

(in thousands)	
Warranty Reserve Balance, December 31, 2010	$2,676
Provision for Warranties Used During the Year	845
Less Settlements Made During the Year	991
Increase in Warranty Estimates for Prior Years	145
Warranty Reserve Balance, September 30, 2011	$2,675

Expenses associated with remediation activities in the Wind Energy segment could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated results of operations and financial condition.

Retainage

Accounts Receivable include the following amounts, billed under contracts by the Company's subsidiaries, that have been retained by customers pending project completion:

(in thousands)	September 30, 2011	December 31, 2010
Accounts Receivable Retained by Customers	$ 12,447	$ 11,848

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Sales of Receivables
DMI is a party to a $40 million receivables sales agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement is subject to renewal in March 2012. The current discount rate is 3-month LIBOR plus 4%. In compliance with guidance under ASC 860-20, Sales of Financial Assets, 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. Following are the amounts of accounts receivable sold and discounts, fees and commissions paid under DMI's receivables sales agreement with General Electric Capital Corporation:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Accounts Receivable Sold	$ 20,662	$ 14,800	$ 48,802	$ 44,100
Discounts, Fees and Commissions Paid on Sale of Accounts Receivable	153	45	406	152

Fair Value Measurements
The Company follows ASC 820, Fair Value Measurements and Disclosures, for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and 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 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 September 30, 2011 and December 31, 2010:

September 30, 2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$513	$--	
Forward Gasoline Purchase Contracts	24		
Forward Energy Contracts		3,929	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		13,560	
Investments of Captive Insurance Company:			
Corporate Debt Securities	9,172		
Proceeds from Sale of Idaho Pacific Holdings, Inc. (IPH) Held in Escrow Account	3,000		
Total Assets	$12,709	$17,489	
Liabilities:			
Forward Energy Contracts	$--	$16,390	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		125	
Total Liabilities	$--	$16,515	

December 31, 2010 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$800	$--	
Forward Gasoline Purchase Contracts	58		
Forward Energy Contracts		6,875	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		12,054	
Investments of Captive Insurance Company:			
Corporate Debt Securities	8,467		
Total Assets	$9,325	$18,929	
Liabilities:			
Forward Energy Contracts	$--	$17,991	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		175	
Total Liabilities	$--	$18,166	

Reclassifications and Changes to Presentation

The Company's consolidated balance sheet as of December 31, 2010, and consolidated income statement and consolidated statement of cash flows for the three and nine months ended September 30, 2010 reflect the reclassifications of the assets and liabilities, operating results and cash flows of IPH and E.W. Wylie's (Wylie) heavy haul and specialized shipment and transportation of wind turbine components business to discontinued operations as a result of second quarter 2011 sale of IPH and the Company's decision to exit the heavy haul and specialized shipment and transportation of wind turbine components business. The Company sold IPH on May 6, 2011. The reclassifications had no impact on the Company's total assets, consolidated net income or cash flows for the three and nine months ended September 30, 2010.

In 2011 management reported Minnesota Conservation Improvement Program (MNCIP) incentives in Operating Revenues – Electric rather than Other Income as they had been classified prior to 2011. The Company has corrected this classification resulting in the following increases in Operating Revenues and Operating Income and decreases in Other Income:

(in thousands)	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
MNCIP Incentives reclassified from Other Income to Operating Revenue	$550	$2,151

The correction had no impact on the Company's net income, total assets, or operating cash flows for the three and nine months ended September 30, 2010.

Inventories
Inventories consist of the following:

(in thousands)	September 30, 2011	December 31, 2010
Finished Goods	$ 26,218	$ 29,113
Work in Process	14,248	7,171
Raw Material, Fuel and Supplies	50,648	42,986
Total Inventories	$ 91,114	$ 79,270

Goodwill
The following table summarizes changes to goodwill by business segment during 2011:

(in thousands)	Gross Balance December 31, 2010	Accumulated Impairments	Balance (net of impairments) December 31, 2010	Adjustments to Goodwill in 2011	Balance (net of impairments) September 30, 2011
Electric	$ 240	$ (240)	$ --	$ --	$ --
Wind Energy	6,959	--	6,959	--	6,959
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	--	7,630
Plastics	19,302	--	19,302	--	19,302
Health Services	23,665	--	23,665	--	23,665
Total	$ 82,241	$ (12,499)	$ 69,742	$ --	$ 69,742

Other Intangible Assets
The following table summarizes the components of the Company's intangible assets at September 30, 2011 and December 31, 2010:

September 30, 2011 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$ 16,811	$ 3,024	$ 13,787	15 – 25 years
Covenants Not to Compete	1,704	1,697	7	3 – 5 years
Other Intangible Assets Including Contracts	1,030	902	128	5 – 30 years
Total	$ 19,545	$ 5,623	$ 13,922	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 1,790	$ --	$ 1,790	
December 31, 2010 (in thousands)				
Amortized Intangible Assets:				
Customer Relationships	$ 16,811	$ 2,388	$ 14,423	15 – 25 years
Covenants Not to Compete	1,704	1,676	28	3 – 5 years
Other Intangible Assets Including Contracts	930	891	39	5 – 30 years
Total	$ 19,445	$ 4,955	$ 14,490	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 1,790	$ --	$ 1,790	

Three Months Ended Nine Months Ended

	September 30,		September 30,	
(in thousands)	2011	2010	2011	2010
Amortization Expense – Intangible Assets	$ 220	$ 238	$ 668	$ 784

(in thousands)	2011	2012	2013	2014	2015
Estimated Amortization Expense – Intangible Assets	$887	$911	$947	$947	$931

Comprehensive Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Net Income (Loss)	$ 6,368	$ 6,101	$ 30,892	$ (3,400)
Other Comprehensive Income (Loss) (net-of-tax):				
Foreign Currency Translation Gains and (Reversal of Previously Recorded Foreign Currency Translation Gains)	--	484	(3,977)	295
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	47	105	(395)	314
Unrealized Gain (Loss) on Available-for-Sale Securities	(2)	54	6	86
Total Other Comprehensive Income (Loss)	45	643	(4,366)	695
Total Comprehensive Income (Loss)	$ 6,413	$ 6,744	$ 26,526	$ (2,705)

Supplemental Disclosures of Cash Flow Information

	Nine Months Ended September 30,	
(in thousands)	2011	2010
Increases in Accounts Payable Related to Capital Expenditures	$ 1,790	$ 63

2. Segment Information

The Company's businesses have been classified into six segments to be consistent with its business strategy and the reporting and review process used by the Company’s chief operating decision makers. These businesses reach customers in all 50 states and international markets. The six segments are: Electric, Wind Energy, Manufacturing, Construction, Plastics and Health Services.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. OTP’s operations have been the Company’s primary business since 1907. Additionally, the electric segment includes Otter Tail Energy Services Company (OTESCO), which provides technical and engineering services, wind farm site development and energy efficient lighting primarily in North Dakota and Minnesota.

Wind Energy consists of two businesses: a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota, Oklahoma and Ontario, Canada, and a trucking company headquartered in West Fargo, North Dakota, specializing in flatbed services and operating in 49 states and six Canadian provinces. Prior to the realignment of the Company's business segments, the wind tower production company was included in Manufacturing and the trucking company was included in Other Business Operations.

Manufacturing consists of businesses in the following manufacturing activities: 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 and Missouri and sell products primarily in the United States.

Construction consists of businesses involved in residential, commercial and industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States. Construction operations were included in Other Business Operations prior to the realignment of the Company's business segments.

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe in the upper Midwest and Southwest regions of 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 equipment and technical staff to various medical institutions located throughout the United States.

Food Ingredient Processing is no longer a reportable segment as a result of the sale of IPH on May 6, 2011. The results of operations, financial position and cash flows of IPH are reported as discontinued operations in the Company's consolidated financial statements.

OTP and OTESCO are wholly owned subsidiaries of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

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 had no single external customer that accounted for 10% or more of the Company's consolidated revenues in 2010. One customer of DMI has accounted for 11.2% of the Company's consolidated revenues in the first nine months of 2011. Substantially all of the Company's long-lived assets are within the United States except for 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, 2011		Three Months Ended September 30, 2010		Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
United States of America	98.2	%	98.9	%	98.2	%	98.2	%
Canada	1.3	%	0.9	%	1.5	%	1.6	%
All Other Countries	0.5	%	0.2	%	0.3	%	0.2	%

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, 2011 and 2010 and total assets by business segment as of September 30, 2011 and December 31, 2010 are presented in the following tables:

Operating Revenue

(in thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Electric	$ 85,172	$ 89,315	$ 254,799	$ 258,294
Wind Energy	65,007	40,389	187,534	134,764
Manufacturing	55,815	43,342	170,486	130,880
Construction	53,247	36,885	139,895	84,808
Plastics	36,231	26,736	99,082	76,562
Health Services	21,853	24,300	67,331	73,116

Corporate Revenues and Intersegment Eliminations		(1,567)		(1,221)		(5,036)		(4,415)
Total	$	315,758	$	259,746	$	914,091	$	754,009

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Interest Charges

(in thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Electric	$ 4,796	$ 5,172	$ 14,874	$ 15,791
Wind Energy	1,925	1,641	5,806	4,511
Manufacturing	1,323	1,298	3,984	3,839
Construction	251	190	698	463
Plastics	411	403	1,176	1,194
Health Services	451	377	1,295	902
Corporate and Intersegment Eliminations	(449)	206	(487)	1,007
Total	$ 8,708	$ 9,287	$ 27,346	$ 27,707

Income Tax Expense (Benefit) – Continuing Operations

(in thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Electric	$ 3,364	$ 4,257	$ 5,972	$ 8,562
Wind Energy	(863)	(3,529)	(4,676)	(5,053)
Manufacturing	591	(349)	3,650	(4,800)
Construction	(115)	435	(195)	(872)
Plastics	1,295	238	3,198	873
Health Services	115	311	863	(66)
Corporate	(2,278)	(1,970)	(4,618)	(5,269)
Total	$ 2,109	$ (607)	$ 4,194	$ (6,625)

Earnings Available for Common Shares

(in thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Electric	$ 10,900	$ 12,265	$ 29,428	$ 24,188
Wind Energy	(3,497)	(7,120)	(16,443)	(9,755)
Manufacturing	1,083	(383)	6,071	(16,234)
Construction	(179)	645	(320)	(1,337)
Plastics	1,970	367	4,908	1,380
Health Services	125	421	1,155	(235)
Corporate	(3,712)	(2,319)	(6,845)	(7,313)
Discontinued Operations	(506)	2,038	12,064	5,256
Total	$ 6,184	$ 5,914	$ 30,018	$ (4,050)

Total Assets

(in thousands)	September 30, 2011	December 31, 2010
Electric	$ 1,101,146	$ 1,106,261

Wind Energy		169,138		172,753
Manufacturing		152,693		144,272
Construction		74,639		60,978
Plastics		84,463		73,508
Health Services		72,566		75,898
Corporate		57,262		43,102
Discontinued Operations		77		93,783
Total	$	1,711,984	$	1,770,555

3. Rate and Regulatory Matters

Minnesota

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010 requesting an 8.01% base rate increase as well as a 3.8% interim rate increase. On May 27, 2010, the Minnesota Public Utilities Commission (MPUC) issued an order accepting the filing, suspending rates, and approving the interim rate increase, as requested, to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. The MPUC authorized a revenue increase of approximately $5.0 million, or 3.76% in base rate revenues, excluding the effect of moving recovery of wind investments to base rates. The MPUC's written order included: (1) recovery of Big Stone II costs over five years (see discussion below), (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of MNCIP costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota fuel clause adjustment (FCA). Final rates went into effect October 1, 2011. The overall increase to customers will be approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund of approximately $3.9 million. As of September 30, 2011, OTP had recognized a $3.9 million refund liability for revenue billed under interim rates from June 1, 2010 through September 30, 2011. On October 31, 2011 OTP issued the interim rate refund, including interest, to Minnesota customers. Pursuant to the order, OTP's allowed rate of return on rate base will increase from 8.33% to 8.61% and its allowed rate of return on equity will increase from 10.43% to 10.74%. OTP's rates of return will be based on a capital structure of 48.28% long term debt and 51.72% common equity.

OTP has a regulatory asset of $3.5 million for revenues that are eligible for recovery through the Minnesota Renewable Resource Adjustment (MNRRA) rider that have not been billed to Minnesota customers as of September 30, 2011. The recovery of MNRRA costs was moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of this regulatory asset.

In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs currently being recovered through OTP's Minnesota Transmission Cost Recovery (TCR) rider to recovery in base rates. Final rates went into effect on October 1, 2011. The Company will continue to utilize the rider cost recovery mechanism until the remaining balance of the current transmission projects has been collected as well as to recover costs associated with approved regional projects. OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. Comments and reply comments have been filed but the MPUC has not yet scheduled a hearing on the request.

Conservation Improvement Program—OTP has a regulatory asset of $7.2 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of September 30, 2011. OTP has recognized $3.7 million in financial incentives relating to 2010. A final decision regarding the 2010 MNCIP financial incentive is expected in December 2011. OTP currently has $1.3 million of income recognized relating to the 2011 MNCIP financial incentive.

North Dakota

Transmission Cost Recovery Rider—North Dakota law 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. OTP requested recovery of such costs in its general rate case filed in November 2008 and was granted recovery of such costs by the North Dakota Public Service Commission (NDPSC) in its November 25, 2009 order. OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29,

2011. The request is under review by the NDPSC.

South Dakota

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the South Dakota Public Utilities Commission (SDPUC) requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. On January 19, 2011 OTP submitted a proposal to use current rate design to implement an interim rate in South Dakota to be effective on and after February 17, 2011. On January 26, 2011 OTP submitted an amended proposal to use a lower interim rate increase than originally proposed. At its February 1, 2011 meeting, the SDPUC approved OTP's request to implement interim rates using current rate design and the lower interim increase to be effective on and after February 17, 2011. On April 21, 2011, the SDPUC issued its written order approving an overall final revenue increase of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50 percent for the interim rates and final rates. Final rates were effective with bills rendered on and after June 1, 2011.

Transmission Cost Recovery Rider—South Dakota law 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. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR has been assigned to an SDPUC outside consultant and likely will not be on an SDPUC agenda until later this year.

Capacity Expansion 2020 (CapX2020)

CapX2020 is a joint initiative of 11 investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kiloVolt (kV) Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji – Grand Rapids Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project.

On April 16, 2009 the MPUC approved Certificates of Need (CONs) for the three 345 kV Group 1 CapX2020 line projects: the Fargo Project, the Brookings Project and the Twin Cities–LaCrosse 345 kV Project.

The Fargo Project—The route permit application for the Monticello to St. Cloud portion of the Fargo Project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers were received in 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the Fargo Project, was accepted by the Federal Energy Regulatory Commission (FERC) in the third quarter of 2010. The Monticello to St. Cloud portion of the Fargo Project is scheduled for completion in December 2011.

The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010 and public hearings were held in November 2010. The MPUC approved the route permit on June 24, 2011. The agreements for Phase 2, which consists of the line section between St. Cloud and Alexandria, Minnesota were signed by all of the participants on August 3, 2011. Easement acquisition discussions with landowners are underway. Construction is expected to begin in November 2011.

On October 8, 2010, OTP submitted its application for a Certificate of Public Convenience and Necessity (CPCN) from the NDPSC for the North Dakota portion of the Fargo Project. The NDPSC approved the CPCN in January

2011. The application for the North Dakota Certificate of Corridor Compatibility (CCC) was filed on December 30, 2010 and was revised in March 2011. The June 23, 2011 hearing for the North Dakota CCC application was postponed. A combined North Dakota CCC and route permit application was submitted to the NDPSC on October 3, 2011.

The Brookings Project—The Minnesota route permit application for the Brookings Project was filed in the fourth quarter of 2008. The MPUC approved the final line segment route permit for the Brookings Project on February 3, 2011.

An application for a South Dakota facility route permit was filed with the SDPUC on November 22, 2010. The SDPUC conducted a public hearing in January 2011 and the South Dakota route permit was approved in June 2011. The MISO board of directors granted conditional approval of the Multi-Value Project (MVP) cost allocation designation under the MISO Tariff for the Brookings Project. Once the MISO board finalizes its analysis of all of the MVP projects in its study portfolio, the MISO board will be in a position to remove the condition, which is anticipated to occur in December 2011. Easement acquisition discussions with landowners are underway.

The Bemidji Project—OTP serves as the lead utility for the Bemidji Project, which has an expected in-service date in late 2012. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 and approved on October 28, 2010. The joint state and federal EIS was published by federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010. On March 25, 2011, the Leech Lake Band of Ojibwe (LLBO) submitted a petition to the MPUC, requesting the revocation or suspension of the project's route permit. The request is based on the LLBO's allegation that it has jurisdiction to require the project to obtain its permission to cross through the historical boundaries of the Leech Lake Reservation. The owners of the Bemidji Project, including OTP, filed reply comments in opposition to the LLBO's request. On April 25, 2011, the Bemidji Project owners filed a declaratory judgment in the U.S. District Court for Minnesota against the LLBO seeking that no consent from the LLBO is required for the project to run through the LLBO reservation boundaries since the project is located exclusively on non LLBO lands. On June 22, 2011, Federal District Judge Frank issued a preliminary injunction which ordered the LLBO to cease and desist from pursuing its claims of jurisdiction over the project in tribal court or the MPUC or from taking any other actions to interfere with the routing or construction of the project. The parties had engaged in court supervised mediation; however, no agreement was reached. The preliminary injunction remains in place prohibiting the LLBO from interfering with project construction.

CapX2020 Request for Advance Determination of Prudence—On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects: the Fargo Project, the Brookings Project and the Bemidji Project. An administrative law judge conducted an evidentiary hearing on the application in May 2010. On October 6, 2010 the NDPSC adopted an order approving a settlement between OTP and intervener NDPSC advocacy staff, and issued an advance determination of prudence to OTP for participation in the three Group 1 projects. The order is subject to a number of terms and conditions in addition to the settlement agreement, including the provision of additional information on the eventual resolution of cost allocation issues relevant to the Brookings Project and its associated impact on North Dakota. On April 29, 2011, OTP filed its compliance filing with the NDPSC, seeking a determination of continued prudence for OTP's investment in the Brookings Project. The NDPSC hearing occurred on July 25, 2011. On August 23, 2011, an executed settlement agreement on continued prudence was filed and the hearing for consideration of the settlement agreement on continued prudence was held on October 26, 2011. A final decision is expected later this year.

Big Stone Air Quality Control System

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and EPA have agreed on non-substantive rule revisions, which were adopted by the Board of Minerals and Environment and became effective on September 19, 2011. South Dakota developed and submitted its revised implementation plan and associated implementation rules to EPA on September 19, 2011. Under the South Dakota implementation plan, and its implementing rules, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. Although studies and evaluations are continuing, the current project cost is estimated to be approximately $490 million (OTP's share would be $264 million). On January 14, 2011 OTP filed a petition asking the MPUC for advance determination of prudence (ADP) for the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. On June 1, 2011, the MPUC referred the matter to the Office of Administrative Hearings for contested case proceedings before an administrative law judge (ALJ). Evidentiary hearings took place on September 14 and 15, 2011 with an ALJ report and recommendation expected by November 9, 2011. A decision by the MPUC is expected in December. OTP filed an application for an ADP with the NDPSC on May 20, 2011 with a decision expected by December 20, 2011. North Dakota has hired a consulting firm to evaluate the ADP request. Evidentiary hearings are scheduled for November 29 and 30, 2011. Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

Big Stone II Project

On June 30, 2005 OTP 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. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II, due to a number of factors. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers was $3,199,000 (which excludes $3,246,000 of project transmission-related costs). Because the MPUC denied OTP an investment return on these deferred costs over the 60-month recovery period, the recoverable amount has been discounted to its present value of $2,758,000, in accordance with ASC 980, Regulated Operations, accounting requirements.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone transmission facilities. The request asks to extend the deadline for filing a CON for these transmission facilities until March 17, 2013. The April 25, 2011 MPUC order instructed OTP to transfer the $3,246,000 Minnesota share of Big Stone II transmission costs to Construction Work in Progress (CWIP) and to create a tracker account through which any over or under recoveries could be accumulated for refund or recovery determination in future rate cases as a regulatory liability or asset. If determined eligible for recovery under the FERC-approved MISO regional transmission tariff, the Minnesota portion of Big Stone II transmission costs and accumulated Allowance for Funds Used During

Construction (AFUDC) will receive rate base treatment and recovery through the FERC-approved MISO regional transmission rates. Any amounts over or under collected through MISO rates will be reflected in the tracker account.

OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately $1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP will be allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. 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, 2011	December 31, 2010	Remaining Recovery/ Refund Period
Regulatory Assets – Current:			
Accrued Cost-of-Energy Revenue	$ 2,552	$ 2,387	23 months
Regulatory Assets – Long Term:			
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 70,265	$ 74,156	see notes
Deferred Marked-to-Market Losses	13,560	12,054	47 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	7,158	6,655	21 months
Minnesota Renewable Resource Rider Accrued Revenues	3,452	6,834	30 months
Big Stone II Unrecovered Project Costs – Minnesota	2,758	6,445	60 months
Debt Reacquisition Premiums	2,582	3,107	252 months
Accumulated ARO Accretion/Depreciation Adjustment	2,545	2,218	asset lives
Big Stone II Unrecovered Project Costs – North Dakota	2,508	3,460	22 months
Deferred Income Taxes	2,025	5,785	asset lives
North Dakota Renewable Resource Rider Accrued Revenues	1,379	2,415	27 months
General Rate Case Recoverable Expenses	1,189	1,773	28 months
Big Stone II Unrecovered Project Costs – South Dakota	936	1,419	112 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	436	717	14 months
South Dakota – Asset-Based Margin Sharing Shortfall	257	501	5 months
Minnesota Transmission Rider Accrued Revenues	252	34	15 months
Deferred Holding Company Formation Costs	152	193	33 months
Total Regulatory Assets – Long Term	$ 111,454	$ 127,766	
Regulatory Liabilities:			
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ 64,031	$ 61,740	asset lives
Deferred Income Taxes	3,691	4,289	asset lives
Minnesota Transmission Rider Accrued Refund	1,081	--	see notes
Deferred Marked-to-Market Gains	125	175	35 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	124	128	267 months
South Dakota – Nonasset-Based Margin Sharing Excess	61	84	15 months
Total Regulatory Liabilities	$ 69,113	$ 66,416	
Net Regulatory Asset Position	$ 44,893	$ 63,737	

The regulatory asset related to the unrecognized transition obligation, prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses 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 and actuarial losses are required to be recognized as components of Accumulated Other

Comprehensive Income in equity under ASC 715, Compensation—Retirement Benefits, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of September 30, 2011 are related to forward purchases of energy scheduled for delivery through August 2015.

Deferred Conservation Program Costs & Accrued Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through 2011 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of September 30, 2011.

Big Stone II Unrecovered Project Costs – Minnesota are the Minnesota share of costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 252 months.

The Accumulated Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

Big Stone II Unrecovered Project Costs – North Dakota are the North Dakota share of costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC 740, Income Taxes.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of September 30, 2011.

General Rate Case Recoverable Expenses relate to expenses incurred during the rate case proceedings that are eligible for recovery.

Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

South Dakota – Asset-Based Margin Sharing Shortfall represents differences in OTP's South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net asset-based margin sharing accumulated shortfalls will be subject to recovery or refund through future retail rate adjustments in South Dakota.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered from Minnesota retail electric customers over 12 months beginning in January 2012.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs, net of salvage revenues, are incurred.

No schedule has been set for the return of the September 30, 2011 Minnesota Transmission Rider Accrued Refund balance.

South Dakota – Nonasset-Based Margin Sharing Excess represents 25% of OTP's South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

If for any reason, OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its 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 guidance under ASC 980 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts

All of OTP'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. OTP'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. OTP'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. OTP 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.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820.

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 September 30, 2011 and December 31, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2010 to September 30, 2011:

(in thousands)		September 30, 2011			December 31, 2010	
Other Current Assets – Marked-to-Market Gain	$	3,929		$	6,875	
Regulatory Assets – Deferred Marked-to-Market Loss		13,560			12,054	
Total Assets		17,489			18,929	
Derivative Liabilities – Marked-to-Market Loss		(16,390	)		(17,991	)
Regulatory Liabilities – Deferred Marked-to-Market Gain		(125	)		(175	)
Total Liabilities		(16,515	)		(18,166	)
Net Fair Value of Marked-to-Market Energy Contracts	$	974		$	763	

(in thousands)		Year-to-Date September 30, 2011	
Fair Value at Beginning of Year	$	763	
Less: Amounts Realized on Contracts Entered into in 2009 and Settled in 2011		(225	)
Amounts Realized on Contracts Entered into in 2010 and Settled in 2011		(28	)
Changes in Fair Value of Contracts Entered into in 2009 in 2011		(14	)
Changes in Fair Value of Contracts Entered into in 2010 in 2011		(72	)
Net Fair Value of Contracts Entered into in 2009 and 2010 at End of Period		424	
Changes in Fair Value of Contracts Entered into in 2011		550	

Net Fair Value End of Period	$	974

The September 30, 2011 balance of recognized but unrealized net mark-to-market gains on the forward energy and capacity purchases and sales is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)		4th Quarter 2011		2012		Total
Net Gain	$	354	$	620	$	974

The following realized and unrealized net gains on forward energy contracts are included in electric operating revenues on the Company's consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Net Gains on Forward Electric Energy Contracts	$ 456	$ 144	$ 587	$ 1,945

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength.

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of September 30, 2011 and December 31, 2010:

	September 30, 2011		December 31, 2010	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$ 792	5	$ 1,129	4
Net Credit Risk to Single Largest Counterparty	$ 372		$ 585	

OTP had no exposure at September 30, 2011 or December 31, 2010 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 credit risk exposures include net amounts due to OTP 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 subsequent to the reporting date. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of September 30, 2011 and December 31, 2010:

Current Liability – Marked-to-Market Loss (in thousands)	September 30, 2011	December 31, 2010
Loss Contracts Covered by Deposited Funds	$ 2,551	$ 427
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	13,803	10,904
Loss Contracts with No Ratings Triggers or Deposit Requirements	36	6,660
Total Current Liability – Marked-to-Market Loss	$ 16,390	$ 17,991

[1] Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.

Contracts Requiring Cash Deposits if OTP’s Credit Falls Below Investment Grade	$	13,803		$	10,904	
Offsetting Gains with Counterparties under Master Netting Agreements		(3,411	)		(6,219	)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$	10,392		$	4,685	

6. Common Shares and Earnings Per Share

Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2010 through September 30, 2011:

Common Shares Outstanding, December 31, 2010	36,002,739
Issuances:	
Restricted Stock Issued to Employees	24,600
Restricted Stock Issued to Nonemployee Directors	24,000
Vesting of Restricted Stock Units	17,325
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(6,641)
Common Shares Outstanding, September 30, 2011	36,062,023

Earnings Per Share

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

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market prices:

Three Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2011	170,960	\$24.93 – \$31.34
2010	383,460	\$24.93 – \$31.34

Nine Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2011	170,960	\$24.93 – \$31.34
2010	383,460	\$24.93 – \$31.34

7. Share-Based Payments

The Company has five share-based payment programs.

Stock Incentive Awards

On April 11, 2011 the Company's Board of Directors granted the following stock incentive awards to the Company's non-employee directors, executive officers and key employees under the 1999 Stock Incentive Plan, as amended:

Award	Shares/Units Granted	Grant-Date Fair Value per Share		Vesting
Restricted Stock Granted to Nonemployee Directors	24,000	$	22.51	25% per year through April 8, 2015
Restricted Stock Granted to Executive Officers	24,600	$	22.51	25% per year through April 8, 2015
SStock Performance Awards Granted to Executive Officers	48,600	$	23.61	December 31, 2013
Restricted Stock Units Granted to Employees	19,800	$	18.03	100% on April 8, 2015

The restricted shares granted to the Company's nonemployee directors and executive officers (which includes OTP's president) are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was the average of the high and low market price per share on the date of grant.

Under the performance share awards, the Company's executive officers could earn up to an aggregate of 97,200 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2011 through December 31, 2013. The aggregate target share award is 48,600 shares. Actual payment may range from zero to 200% of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The grant date fair value of the target amount of common shares projected to be awarded was determined under a Monte Carlo simulation valuation method. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC 718-10-25-18, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

The grant date fair value of each restricted stock unit was based on the market value of one share of the Company's common stock on the grant date, discounted for the value of the dividend exclusion over the four-year vesting period.

As of September 30, 2011 the remaining unrecognized compensation expense related to stock-based compensation was approximately $2.8 million (before income taxes) which will be amortized over a weighted-average period of 2.6 years.

Compensation expense recognized under the Company's stock-based payment programs:

	Three Months Ended September 30,				Nine Months Ended September 30,			
(in thousands)		2011		2010		2011		2010
Employee Stock Purchase Plan (15% discount)	$	51	$	64	$	185	$	205
		185		148		571		446

Restricted Stock Granted to Directors				
Restricted Stock Granted to Employees	511	239	759	519
Stock Performance Awards Granted to Executive Officers	1,766	722	1,766	879
Restricted Stock Units Granted to Employees	92	(20)	244	137
Totals	$ 2,605	$ 1,153	$ 3,525	$ 2,186

9. Commitments and Contingencies

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts
In the first quarter of 2011, OTP entered into additional energy purchase agreements increasing its commitments for capacity and energy requirements. Amounts of commitments for OTP's capacity and energy requirements under agreements extending through 2032 were as follows:

Capacity and Energy Requirements (thousands)	September 30, 2011	December 31, 2010	Increase
2011	$ 21,268	$ 20,134	$ 1,134
2012	25,025	21,637	3,388
2013	21,868	16,492	5,376
2014	24,701	15,388	9,313
2015	18,915	12,307	6,608
Beyond 2015	78,879	78,879	--
Total	$ 190,656	$ 164,837	$ 25,819

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. In the first half of 2011, OTP extended its contract for the purchase of coal for Hoot Lake Plant resulting in an increase in minimum purchase commitments. OTP's current coal purchase agreements under contracts expire in 2012 and 2016. OTP is now committed to the minimum purchase, dating from January 1, 2011, or to make payments in lieu thereof in the following amounts:

Coal and Freight Purchase Commitments (thousands)	September 30, 2011	December 31, 2010	Increase
2011	$ 52,819	$ 47,122	$ 5,697
2012	48,444	34,958	13,486
2013	9,855	9,855	--
2014	9,854	9,854	--
2015	9,854	9,854	--
Beyond 2015	4,106	4,106	--
Total	$ 134,932	$ 115,749	$ 19,183

The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

Other
The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of September 30, 2011 will not be material.

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood that a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to product warranty, environmental remediation, litigation matters, possible liquidated damages and the resolution of matters related to open tax years. Should any of these items result in a liability being incurred, the range of loss could be as high as $9.0 million. Additionally, we may become subject to significant claims of which we are unaware, or the claims of which we are aware may result in our incurring a significantly greater liability than we anticipate.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of September 30, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on September 30, 2011	Restricted due to Outstanding Letters of Credit	Available on September 30, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$ 200,000	$ 20,000	$ 1,374	$ 178,626	$ 144,350
OTP Credit Agreement	170,000	19,010	1,050	149,940	144,436
Total	$ 370,000	$ 39,010	$ 2,424	$ 328,566	$ 288,786

On March 3, 2011 OTP entered into an Amended and Restated Credit Agreement (the OTP Credit Agreement) with the Banks named therein. The OTP Credit Agreement provides for a $170 million line of credit that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under the line of credit currently bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP's senior unsecured debt. Under the OTP Credit Agreement OTP is required to pay the Banks' commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement expires on March 3, 2016.

The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The OTP Credit Agreement amends and restates the $170 million Credit Agreement dated as of July 30, 2008 among OTP (formerly known as Otter Tail Corporation, dba Otter Tail Power Company), the Banks named therein, as amended by a First Amendment to Credit Agreement dated as of April 21, 2009 and a Second Amendment to Credit Agreement dated as of June 22, 2009.

The OTP Credit Agreement also contains certain financial covenants. Specifically, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization (as defined in the OTP Credit Agreement) to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (as defined in the OTP Credit Agreement) to be less than 1.50 to 1.00.

On March 18, 2011 Otter Tail Corporation borrowed $1.5 million under a Partnership in Assisting Community Expansion loan to finance capital investments at Northern Pipe Products, Inc. (NPP), the Company's PVC pipe manufacturing subsidiary located in Fargo, North Dakota. The ten-year unsecured note bears interest at 2.54% with monthly principal and interest payments through March 2021. On April 6, 2011 Otter Tail Corporation borrowed $0.5 million under a North Dakota Development Fund loan to finance additional capital investments at NPP. The seven-year unsecured note bears interest at 3.95% with monthly principal and interest payments through April 1, 2018.

On July 29, 2011, OTP entered into a Note Purchase Agreement with the purchasers named therein, pursuant to which OTP has agreed to issue to the purchasers in a private placement transaction $140 million aggregate principal amount of OTP's 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes). The 2021 Notes are expected to be issued on December 1, 2011, subject to the satisfaction of certain customary conditions to closing. OTP intends to use a portion of the proceeds of the 2021 Notes to retire $90 million aggregate principal amount of OTP's 6.63% Senior Notes due December 1, 2011 and $10.4 million aggregate principal amount of its pollution control refunding revenue bonds due December 1, 2012. The remaining proceeds of the 2021 Notes will be used to repay short-term debt of OTP, to pay fees and expenses related to the issuance of the 2021 Notes and for other general corporate purposes.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of September 30, 2011 and December 31, 2010:

September 30, 2011 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 19,010	$ 65	$ 20,000	$ 39,075
Long-Term Debt:				
Senior Unsecured Notes 6.63%, due December 1, 2011	$ 90,000			$ 90,000
Pollution Control Refunding Revenue Bonds, Variable, 1.50% at September 30, 2011, due December 1, 2012	10,400			10,400
9.000% Notes, due December 15, 2016			$ 100,000	100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,090			5,090
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,105			20,105
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Other Obligations - Various up to 13.31% at September 30, 2011		$ 4,220	1,929	6,149
Total	$ 280,595	$ 4,220	$ 151,929	$ 436,744
Less: Current Maturities	--	3,124	162	3,286
Unamortized Debt Discount	--	--	4	4
Total Long-Term Debt	$ 280,595	$ 1,096	$ 151,763	$ 433,454
Total Short-Term and Long-Term Debt (with current maturities)	$ 299,605	$ 4,285	$ 171,925	$ 475,815

December 31, 2010 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 25,314	$--	$ 54,176	$ 79,490
Long-Term Debt:				
Senior Unsecured Notes 6.63%, due December 1, 2011	$ 90,000			$ 90,000

Pollution Control Refunding Revenue Bonds, Variable, 2.50% at December 31, 2010, due December 1, 2012		10,400						10,400
9.000% Notes, due December 15, 2016					$	100,000		100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		33,000						33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		5,100						5,100
Senior Unsecured Note 8.89%, due November 30, 2017						50,000		50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		30,000						30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		20,215						20,215
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027		42,000						42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037		50,000						50,000
Other Obligations - Various up to 13.31% at December 31, 2010			$	4,706				4,706
Total	$	280,715	$	4,706	$	150,000	$	435,421
Less: Current Maturities		--		604		--		604
Unamortized Debt Discount		--		--		5		5
Total Long-Term Debt	$	280,715	$	4,102	$	149,995	$	434,812
Total Short-Term and Long-Term Debt (with current maturities)	$	306,029	$	4,706	$	204,171	$	514,906

11. Class B Stock Options of Subsidiary

In conjunction with the sale of IPH on May 6, 2011, all 363 outstanding IPH Class B common share options were cancelled by mutual agreement between the issuer and the holders of the options and a liability to the holders of the options was established based on the fair value of the options on May 6, 2011. The liability was assumed by the new owner of IPH. The options were adjusted to their fair value based on the fair value of an underlying share of Class B Common Stock of $2,973.90 per share on May 6, 2011. The book value of IPH Class B common share options prior to their cancellation on May 6, 2011 was based on an IPH Class B common share value of $2,085.88 per share. The $322,000 difference between the fair value and book value of the options was charged to retained earnings and earnings available for common shares were reduced by $322,000 in the second quarter of 2011.

12. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Service Cost—Benefit Earned During the Period	$ 961	$ 997	$ 3,311	$ 3,491
Interest Cost on Projected Benefit Obligation	3,150	2,990	9,500	9,050
Expected Return on Assets	(3,530)	(3,483)	(10,605)	(10,283)
Amortization of Prior-Service Cost	125	172	325	512
Amortization of Net Actuarial Loss	663	511	1,963	1,501
Net Periodic Pension Cost	$ 1,369	$ 1,187	$ 4,494	$ 4,271

The Company did not make a contribution to its pension plan in the nine months ended September 30, 2011 and is not currently required to make a contribution in 2011.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Service Cost—Benefit Earned During the Period	$ 20	$ 165	$ 61	$ 495
Interest Cost on Projected Benefit Obligation	407	417	1,223	1,253
Amortization of Prior-Service Cost	18	19	55	55
Amortization of Net Actuarial Loss	62	120	184	358
Net Periodic Pension Cost	$ 507	$ 721	$ 1,523	$ 2,161

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Service Cost—Benefit Earned During the Period	$ 425	$ 375	$ 1,275	$ 1,225
Interest Cost on Projected Benefit Obligation	850	855	2,550	2,405
Amortization of Transition Obligation	187	187	561	561
Amortization of Prior-Service Cost	50	58	150	158
Amortization of Net Actuarial Loss	213	248	639	624
Effect of Medicare Part D Expected Subsidy	(525)	(558)	(1,575)	(1,558)
Net Periodic Postretirement Benefit Cost	$ 1,200	$ 1,165	$ 3,600	$ 3,415

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13. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Long-Term Debt—The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. The Company’s long-term debt subject to variable interest rates approximates fair value.

	September 30, 2011		December 31, 2010	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 6,604	$ 6,604	$ --	$ --
Long-Term Debt	(433,454)	(479,567)	(434,812)	(474,307)

15. Income Tax Expense (Benefit) – Continuing Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Income (Loss) Before Income Taxes – Continuing Operations	$ 8,983	$ 3,454	$ 22,700	$ (15,379)
Income Tax Expense (Benefit) – Continuing Operations	2,109	(607)	4,194	(6,625)
Effective Income Tax Rate – Continuing Operations	23.5 %	(17.6)%	18.5 %	43.1 %

The increase in Income Tax Expense (Benefit) - Continuing Operations for the three months ended September 30, 2011 compared with the three months ended September 30, 2010 is mainly due to the increase in income before income taxes between the quarters, but also due to DMI deferring recognition of tax benefits in the third quarter of 2011 on the operating losses of its Canadian wind tower manufacturing company until those operations become profitable. DMI’s deferred tax benefits totaled $0.5 million in the third quarter of 2011. The Company’s effective income tax rates for the three months ended September 30, 2011 and 2010 were decreased as a result of recording $1.4 million and $1.6 million, respectively, in federal production tax credits (PTCs) earned on kilowatt-hours (kwhs) generated from tax credit qualified wind turbines owned by OTP.

The increase in Income Tax Expense (Benefit) - Continuing Operations for the nine months ended September 30, 2011 compared with the nine months ended September 30, 2010 is mainly due to the increase in income before income taxes between the periods. Also, only $2.8 million of ShoreMaster’s $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes and DMI is deferring recognition of tax benefits in the first nine months of 2011 on the operating losses of its Canadian wind tower manufacturing company until those operations become profitable. DMI’s 2011 deferred tax benefits totaled $2.4 million through September 30, 2011. The

Company’s effective income tax rates for the nine months ended September 30, 2011 and 2010 were decreased as a result of recording $5.3 million and $4.7 million, respectively, in federal PTCs earned on kwhs generated from tax credit qualified wind turbines owned by OTP.

17. Discontinued Operations

On May 6, 2011, the Company completed the sale of IPH to affiliates of Novacap Industries III, L.P. for approximately $87.0 million in cash. The proceeds from the sale, net of $3.0 million deposited in an escrow account, were used to pay down borrowings under the Otter Tail Corporation Credit Agreement. In the second quarter of 2011, Wylie decided to exit its heavy haul/specialized shipment and transportation of wind turbine components business, determining that the risks associated with continuing to provide these services outweighed any potential profits to be derived from these operations. The financial position, results of operations, and cash flows of IPH and Wylie's specialized shipment and transportation of wind turbine components business are reported as discontinued operations in the Company's consolidated financial statements as of September 30, 2011 and December 31, 2010, and for the three and nine month periods ended September 30, 2011 and 2010. Following are summary presentations of the results of discontinued operations for the three and nine month periods ended September 30, 2011 and 2010 and of the major components of assets and liabilities of discontinued operations as of September 30, 2011 and December 31, 2010:

	Three Months Ended					
	September 30, 2011			September 30, 2010		
(in thousands)	IPH	Wylie-Wind	Total	IPH	Wylie-Wind	Total
Operating Revenues	$--	$ --	$--	$19,478	$ 2,046	$21,524
Income (Loss) Before Income Taxes	$--	$ (86)	$(86)	$3,183	$ 82	$3,265
Gain (Loss) on Disposition - Pretax	(756)	--	(756)	--	--	--
Income Tax Expense (Benefit)	(302)	(34)	(336)	1,192	33	1,225
Net Income (Loss)	$(454)	$ (52)	$(506)	$1,991	$ 49	$2,040

	Nine Months Ended					
	September 30, 2011			September 30, 2010		
(in thousands)	IPH	Wylie-Wind	Total	IPH	Wylie-Wind	Total
Operating Revenues	$28,125	$ 5,448	$33,573	$56,648	$ 4,700	$61,348
Income (Loss) Before Income Taxes	$3,840	$ (4,650)	$(810)	$8,306	$ 129	$8,435
Gain on Disposition - Pretax	16,011	--	16,011	--	--	--
Income Tax Expense (Benefit)	4,675	(1,860)	2,815	3,029	52	3,081
Net Income (Loss)	$15,176	$ (2,790)	$12,386	$5,277	$ 77	$5,354

	September 30, 2011		December 31, 2010		
(in thousands)	Wylie-Wind	Total	IPH	Wylie-Wind	Total
Current Assets	$2	$2	$24,836	$ 2,461	$27,297
Goodwill	--	--	24,324	--	24,324
Other Intangibles - Net	--	--	10,852	--	10,852
Net Plant	75	75	30,672	638	31,310
Assets of Discontinued Operations	$77	$77	$90,684	$ 3,099	$93,783
Current Liabilities	$77	$77	$6,839	$ 4,150	$10,989
Deferred Income Taxes	--	--	11,553	--	11,553
Long-Term Debt	--	--	634	--	634
Liabilities of Discontinued Operations	$77	$77	$19,026	$ 4,150	$23,176

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Because IPH was a material subsidiary, the Company is providing the following pro forma summary presentations of its consolidated income statements for the years ended December 31, 2010 and 2009, reflecting the classification of IPH's results as discontinued operations:

Otter Tail Corporation
Summary Consolidated Income Statements
For the Years Ended December 31,

(in thousands, except per share amounts)	2010 As Previously Reported	2010 IPH1	2010 With IPH classified as Discontinued Operations	2009 As Previously Reported	2009 IPH1	2009 With IPH classified as Discontinued Operations
Operating Revenues	$1,119,084	$77,202	$ 1,041,882	$1,039,512	$78,632	$ 960,880
Operating Expenses:						
Cost of Goods Sold	600,956	56,619	544,337	565,192	58,718	506,474
Other Operating Expenses	402,919	3,729	399,190	355,322	3,330	351,992
Depreciation Expense	80,696	4,703	75,993	73,608	4,333	69,275
Total Operating Expenses	1,084,571	65,051	1,019,520	994,122	66,381	927,741
Operating Income	34,513	12,151	22,362	45,390	12,251	33,139
Other Income (Deductions)	5,126	(408)	5,534	4,550	(404)	4,954
Interest Charges	37,032	29	37,003	28,514	30	28,484
Income Tax Expense (Benefit)	3,951	3,716	235	(4,605)	4,410	(9,015)
Net Income - Continuing Operations	(1,344)	7,998	(9,342)	26,031	7,407	18,624
Net Income – Discontinued Operations			7,998			7,407
Net Income (Loss)	(1,344)	7,998	(1,344)	26,031	7,407	26,031
Preferred Dividend Requirements	833	--	833	736	--	736
Earnings Available for Common Shares	$(2,177)	$7,998	$ (2,177)	$25,295	$7,407	$ 25,295
Basic Earnings Per Common Share:						
Continuing Operations (net of preferred dividend requirement)	$(0.06)	$0.22	$ (0.28)	$0.71	$0.21	$ 0.50
Discontinued Operations			0.22			0.21
			$ (0.06)			$ 0.71
Diluted Earnings Per Common Share:						
Continuing Operations (net of preferred dividend requirement)	$(0.06)	$0.22	$ (0.28)	$0.71	$0.21	$ 0.50
Discontinued Operations			0.22			0.21
			$ (0.06)			$ 0.71

1Includes reinstatement of intercompany eliminations related to intercompany transactions with IPH.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and nine month periods ended September 30, 2011 and 2010, followed by a discussion of changes in our consolidated financial position during the nine months ended September 30, 2011 and our business outlook for the remainder of 2011.

Comparison of the Three Months Ended September 30, 2011 and 2010

Consolidated operating revenues were $315.8 million for the three months ended September 30, 2011 compared with $259.7 million for the three months ended September 30, 2010. Operating income was $17.2 million for the three months ended September 30, 2011 compared with operating income of $12.0 million for the three months ended September 30, 2010. The Company recorded diluted earnings per share from continuing operations of $0.18 for the three months ended September 30, 2011 compared with $0.11 for the three months ended September 30, 2010 and total diluted earnings per share of $0.17 for the three months ended September 30, 2011 compared with $0.16 for the three months ended September 30, 2010.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended September 30, 2011 and 2010 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations (in thousands)	September 30, 2011	September 30, 2010
Operating Revenues:		
Electric	$ 55	$ 43
Nonelectric	1,512	1,178
Cost of Goods Sold	1,507	1,150
Other Nonelectric Expenses	60	71

Electric

	Three Months Ended September 30,			
(in thousands)	2011	2010	Change	% Change
Retail Sales Revenues	$ 73,766	$ 77,779	$ (4,013)	(5.2)
Wholesale Revenues – Company Generation	6,107	7,313	(1,206)	(16.5)
Net Revenue – Energy Trading Activity	592	239	353	147.7
Other Revenues	4,707	3,984	723	18.1
Total Operating Revenues	$ 85,172	$ 89,315	$ (4,143)	(4.6)
Production Fuel	19,080	18,210	870	4.8
Purchased Power – System Use	7,488	10,254	(2,766)	(27.0)
Other Operation and Maintenance Expenses	27,323	27,098	225	0.8
Depreciation and Amortization	10,046	10,036	10	0.1
Property Taxes	2,601	2,271	330	14.5
Operating Income	$ 18,634	$ 21,446	$ (2,812)	(13.1)

The $4.0 million decrease in retail sales revenues reflects: (1) a $2.5 million decrease in revenues mainly due to a 1.0% decrease in total retail kilowatt-hour (kwh) sales driven by decreases in commercial and industrial kwh sales, (2) a $0.6 million reduction in revenue related to the recovery of lower fuel and purchased power costs, (3) a $0.5 million decrease in resource recovery and transmission rider revenues, and (4) a $0.4 million refund accrual for excess amounts collected under interim rates in Minnesota in the third quarter of 2011. Revenues related to the recovery of fuel and purchased power costs decreased as a result of a reduction in purchased power costs in excess of an increase in fuel costs incurred to serve retail load.

Wholesale electric revenues from company-owned generation decreased $1.2 million due to a 23.0% decline in wholesale kwh sales, partially offset by an 8.4% increase in the average price per wholesale kwh sold, as a result of a 5.8% reduction in kwh generation at Otter Tail Power Company (OTP) generating units and lower demand in wholesale markets. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, increased $0.4 million mainly as a result of an increase in mark-to-market gains on OTP’s open energy contracts. Other electric operating revenues increased $0.7 million as a result of an increase in transmission tariff revenues.

The $0.9 million increase in fuel costs is due to a 9.4% increase in the cost of fuel per kwh generated, partially offset by a 4.3% decrease in kwhs generated from OTP’s steam-powered and combustion turbine generators. The cost of purchased power for retail sales decreased $2.8 million as a result of a 40.2% decrease in kwhs purchased, partially offset by 22.1% increase in the cost per kwh purchased. The $0.3 million increase in property taxes reflects increases in Minnesota and South Dakota property taxes due to capital additions and increases in assessments, assessed values and the percentage of a property’s assessed value subject to taxation in those states.

Wind Energy

In the second quarter of 2011, E. W. Wylie Corporation (Wylie) exited the wind-heavy haul business. Accordingly, the results of operations of Wylie’s wind-heavy haul business are reported as discontinued operations.

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Wind Tower Revenues	$ 52,595	$ 29,330	$ 23,265	79.3
Transportation Revenues	12,412	11,059	1,353	12.2
Total Operating Revenues	$ 65,007	$ 40,389	24,618	61.0
Cost of Goods Sold	48,893	33,847	15,046	44.5
Operating Expenses	15,635	12,689	2,946	23.2
Depreciation and Amortization	3,005	2,803	202	7.2
Operating Loss	$ (2,526)	$ (8,950)	$ 6,424	(71.8)

The increase in revenues in our Wind Energy segment relates to the following:

Revenues at DMI Industries, Inc. (DMI), our manufacturer of wind towers, increased as a result of a 70.8% increase in tower production.

Revenues at Wylie, our flatbed trucking company, increased mainly as a result of an increase in fuel surcharge revenues related to a 33.0% increase in the average cost per gallon of fuel consumed.

The increase in cost of goods sold in our Wind Energy segment relates to the following:

Cost of goods sold at DMI increased $15.0 million, reflecting $16.9 million in increased costs related to the increase in towers produced, partially offset by a $1.1 million decrease in indirect material costs and $0.9 million in productivity gains mainly due to a reduction in costs incurred to rework towers.

The net increase in operating expenses in our Wind Energy segment relates to the following:

Operating expenses at DMI decreased $0.3 million between the quarters as a result of decreases in expenditures for building repairs and maintenance and professional services.

Operating expenses at Wylie increased $3.2 million as a result of increases in fuel prices, contractor and brokerage settlement costs and insurance costs.

Manufacturing

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 55,815	$ 43,342	$ 12,473	28.8
Cost of Goods Sold	43,292	33,176	10,116	30.5
Operating Expenses	6,293	6,450	(157)	(2.4)
Depreciation and Amortization	3,233	3,155	78	2.5
Operating Income	$ 2,997	$ 561	$ 2,436	434.2

The increase in revenues in our Manufacturing segment relates to the following:

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, increased $9.8 million as a result of higher sales volume due to improved customer demand for products and services.

Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment business, increased $2.8 million due to increased sales of both residential and commercial products.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased by $0.1 million due to a slight decrease in sales volume.

The increase in cost of goods sold in our Manufacturing segment relates to the following:

Cost of goods sold at BTD increased $7.8 million mainly as a result of increased sales volume.

Cost of goods sold at ShoreMaster increased $1.9 million as a result of increased sales volume.

Cost of goods sold at T.O. Plastics increased $0.4 million as a result of increases in material and overhead costs.

The net decrease in operating expenses in our Manufacturing segment is due to the following:

Operating expenses at BTD increased $0.6 million due to increases in salary and benefit costs related to workforce expansion and increased promotional expenses.

Operating expenses at ShoreMaster decreased $0.8 million, reflecting a $0.4 million decrease to its allowance for doubtful accounts between the quarters and a $0.4 million decrease in labor and benefit costs.

Operating expenses at T.O. Plastics increased by less than $0.1 million between the quarters.

Construction

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 53,247	$ 36,885	$ 16,362	44.4
Cost of Goods Sold	49,740	32,066	17,674	55.1
Operating Expenses	3,063	3,052	11	0.4
Depreciation and Amortization	523	510	13	2.5
Operating (Loss) Income	$ (79)	$ 1,257	$ (1,336)	(106.3)

The increase in revenues in our Construction segment relates to the following:

Revenues at Foley Company, a mechanical and prime contractor on industrial projects, increased $14.9 million due to an increase in the magnitude and volume of jobs in progress.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $1.4 million, reflecting $2.9 million in increased revenue from electrical and data wiring work and construction of underground and overhead electric transmission and distribution lines, offset by a $1.5 million reduction in revenues from work on substation and wind power projects.

The increase in cost of goods sold in our Construction segment relates to the following:

Cost of goods sold at Foley Company increased $15.5 million, mainly in the areas of material and subcontractor costs related to the increase in Foley's work volume between the quarters, but also due to $0.8 million in cost overruns recorded on one large project in the third quarter of 2011.

Cost of goods sold at Aevenia increased $2.2 million, mainly in labor and material costs, as a result of increased construction activity.

Plastics

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 36,231	$ 26,736	$ 9,495	35.5
Cost of Goods Sold	29,956	23,278	6,678	28.7
Operating Expenses	1,756	1,606	150	9.3
Depreciation and Amortization	851	858	(7)	(0.8)
Operating Income	$ 3,668	$ 994	$ 2,674	269.0

Operating revenues for the Plastics segment increased as result of a 5.2% increase in pounds of pipe sold combined with a 28.8% increase in the price per pound of pipe sold. The increase in costs of goods sold was due to the increase in pounds of pipe sold combined with a 22.3% increase in the cost per pound of pipe sold. The increase in operating expenses is mainly due to an increase in sales commissions paid as a result of the increase in pounds of pipe sold.

Health Services

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 21,853	$ 24,300	$ (2,447)	(10.1)
Cost of Goods Sold	14,590	17,186	(2,596)	(15.1)
Operating Expenses	4,489	4,353	136	3.1
Depreciation and Amortization	2,144	1,694	450	26.6
Operating Income	$ 630	$ 1,067	$ (437)	(41.0)

Revenues from scanning and other related services decreased $2.0 million as a result of an 8.5% reduction in scans performed. Revenues from equipment sales and servicing decreased $0.4 million. The decrease in cost of goods sold reflects a $2.3 million reduction in equipment rental costs directly related to efforts by the Health Services segment to right-size its fleet of imaging assets by exercising purchase options on productive imaging assets coming off lease and not renewing leases on underutilized imaging assets. The increase in operating expenses is mainly due to an increase in labor costs. The increase in depreciation expense reflects an increase in owned equipment compared with a year ago.

Corporate

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

(in thousands)	Three Months Ended September 30, 2011	2010	Change	% Change
Operating Expenses	$ 5,987	$ 4,219	$ 1,768	41.9
Depreciation and Amortization	135	119	16	13.4

The increase in corporate operating expenses is mainly due to the accrual of termination benefits related to the resignation of our chief executive officer in the third quarter of 2011.

Interest Charges

Interest charges decreased $0.6 million in the third quarter of 2011 compared with the third quarter of 2010 mainly as a result of a $46.1 million decrease in the average balance of short-term debt outstanding between the quarters, due in part to the pay down of borrowings under our line of credit facility from proceeds from the sale of Idaho Pacific Holdings, Inc. (IPH) in May 2011.

Income Taxes – Continuing Operations

	Three Months Ended September 30,		
(in thousands)	2011	2010	Variance
Income Before Income Taxes – Continuing Operations	$ 8,983	$ 3,454	$ 5,529
Income Tax Expense (Benefit) - Continuing Operations	2,109	(607)	2,716
Effective Income Tax Rate – Continuing Operations	23.5 %	(17.6)%	

The increase in Income Tax Expense (Benefit) - Continuing Operations for the three months ended September 30, 2011 compared with the three months ended September 30, 2010 is mainly due to the increase in income before income taxes between the quarters, but is also due to DMI deferring recognition of tax benefits in the third quarter of 2011 on the operating losses of its Canadian wind tower manufacturing company until those operations become profitable. DMI's deferred tax benefits totaled $0.5 million in the third quarter of 2011. Our effective income tax rates for the three months ended September 30, 2011 and 2010 decreased as a result of recording $1.4 million and $1.6 million, respectively, in federal production tax credits (PTCs) earned on kwhs generated from tax credit qualified wind turbines owned by OTP. Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes.

Discontinued Operations

On May 6, 2011, we completed the sale of IPH to affiliates of Novacap Industries III, L.P. for approximately $87.0 million in cash. The proceeds from the sale, net of $3.0 million deposited in an escrow account, were used to pay down borrowings under our existing credit agreement. In the second quarter of 2011, Wylie decided to discontinue its heavy haul and specialized shipment and transportation of wind turbine components business. In the third quarter of 2011, the IPH sales proceeds were reduced by $0.8 million related to a purchase price adjustment. The results of operations of IPH and of Wylie's wind turbine component transport business are reported as discontinued operations in our consolidated statements of income for the three months ended September 30, 2011 and 2010 as summarized in the table below:

	Three Months Ended					
	September 30, 2011			September 30, 2010		
(in thousands)	IPH	Wylie-Wind	Total	IPH	Wylie-Wind	Total
Operating Revenues	$--	$ --	$--	$19,478	$ 2,046	$21,524
Income (Loss) Before Income Taxes	$--	$ (86)	$(86)	$3,183	$ 82	$3,265
Loss on Disposition - Pretax	(756)	--	(756)	--	--	--
Income Tax Expense (Benefit)	(302)	(34)	(336)	1,192	33	1,225
Net Income (Loss)	$(454)	$ (52)	$(506)	$1,991	$ 49	$2,040

Comparison of the Nine Months Ended September 30, 2011 and 2010

Consolidated operating revenues were $914.1 million for the nine months ended September 30, 2011 compared with $754.0 million for the nine months ended September 30, 2010. Operating income was $47.7 million for the nine months ended September 30, 2011 compared with operating income of $11.1 million for the nine months ended September 30, 2010. The Company recorded diluted earnings per share from continuing operations of $0.50 for the nine months ended September 30, 2011 compared with $(0.26) for the nine months ended September 30, 2010 and total diluted earnings per share of $0.83 for the nine months ended September 30, 2011 compared with $(0.11) for the nine months ended September 30, 2010.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the nine month periods ended September 30, 2011 and 2010 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations (in thousands)	September 30, 2011	September 30, 2010
Operating Revenues:		
Electric	$ 181	$ 164
Nonelectric	4,855	4,251
Cost of Goods Sold	4,667	3,875
Other Nonelectric Expenses	369	540

Electric

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Retail Sales Revenues	$ 224,371	$ 226,945	$ (2,574)	(1.1)
Wholesale Revenues – Company Generation	12,406	16,506	(4,100)	(24.8)
Net Revenue – Energy Trading Activity	1,570	2,765	(1,195)	(43.2)
Other Revenues	16,452	12,078	4,374	36.2
Total Operating Revenues	$ 254,799	$ 258,294	$ (3,495)	(1.4)
Production Fuel	55,737	55,611	126	0.2
Purchased Power – System Use	27,759	32,730	(4,971)	(15.2)
Other Operation and Maintenance Expenses	84,718	84,817	(99)	(0.1)
Depreciation and Amortization	30,105	30,111	(6)	--
Property Taxes	7,427	7,222	205	2.8
Operating Income	$ 49,053	$ 47,803	$ 1,250	2.6

The $2.6 million decrease in retail sales revenues mainly is due to the following: (1) a $2.2 million reduction in retail revenue related to the recovery of lower fuel and purchased power costs, (2) a $1.4 million net reduction in revenues related to a $2.5 million increase in Minnesota revenues collected under interim rates net of a $3.9 million refund accrual for excess amounts collected under interim rates since June 2010, (3) a $1.2 million reduction in Minnesota resource recovery and transmission rider revenues, (4) a $0.8 million decrease in North Dakota resource recovery rider revenues, and (5) a $0.4 million decrease related to a North Dakota rate of return refund in the second quarter of 2011, partially offset by (6) a $3.4 million increase in revenues mainly due to a 1.8% increase in retail kwh sales driven by colder weather in the first half of 2011 compared with the first half of 2010, as indicated by a 17.0% increase in heating degree days between those periods.

Wholesale electric revenues from company-owned generation decreased $4.1 million due to a 17.2% decrease in wholesale kwh sales combined with a 9.2% decrease in revenue per wholesale kwh sold as a result of a 3.8% reduction in kwh generation from OTP's generating units and lower demand in wholesale markets. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, decreased $1.2 million as a result of a reduction in mark-to-market gains on open energy contracts combined with a reduction in the volume of long-term forward energy contracts entered into in 2011. Other electric operating revenues increased $4.4 million as a result of: (1) a $2.0 million increase in transmission tariff and services revenue between the periods, (2) $1.3 million in payments from a transmission cooperative to Otter Tail Energy Services Company (OTESCO) in 2011 for access rights and assistance in obtaining easements from landowners to construct a high voltage transmission line through a wind farm site where OTESCO owns development rights, and (3) a June 2010 refund accrual of $1.1 million for excess overhead charged to Big Stone II partners.

The $0.1 million increase in fuel costs reflects a 5.6% increase in the cost of fuel per kwh generated, offset by 5.1% reduction in kwhs generated from OTP's steam-powered and combustion turbine generators. The cost of purchased power for retail sales decreased $5.0 million mainly as a result of a 14.0% decrease in the cost per kwh purchased due to lower market prices for electricity combined with a 1.4% decrease in kwhs purchased.

Wind Energy

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Wind Tower Revenues	$ 154,605	$ 105,934	$ 48,671	45.9
Transportation Revenues	32,929	28,830	4,099	14.2
Total Operating Revenues	$ 187,534	$ 134,764	52,770	39.2
Cost of Goods Sold	152,621	100,504	52,117	51.9
Operating Expenses	41,568	35,767	5,801	16.2
Depreciation and Amortization	8,588	8,279	309	3.7
Operating Loss	$ (15,243)	$ (9,786)	$ (5,457)	55.8

The increase in revenues in our Wind Energy segment relates to the following:

Revenues at DMI increased as a result of a 47.6% increase in tower production.

Revenues at Wylie increased mainly as a result of an increase in fuel surcharge revenues related to a 34.3% increase in the average cost per gallon of fuel consumed and also due to a $0.6 million increase in brokerage revenues.

The increase in cost of goods sold in our Wind Energy segment relates to the following:

Cost of goods sold at DMI increased $51.9 million reflecting $46.8 million in increased costs related to the increase in towers produced, a $2.8 million increase in outsourced quality control costs to satisfy expanded customer requirements, productivity losses of $1.1 million due to rework and underutilization of plant capacity, and $1.1 million from the absorption of higher steel costs when a supplier did not fulfill its delivery requirements.

The net increase in operating expenses in our Wind Energy segment relates to the following:

Operating expenses at DMI decreased $0.2 million as a result of a decrease in expenditures for building repairs and maintenance.

Operating expenses at Wylie increased $6.0 million as a result of increases in fuel prices, subcontractor and brokerage fees, repairs and maintenance expenses and insurance costs.

Manufacturing

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 170,486	$ 130,880	$ 39,606	30.3
Cost of Goods Sold	129,617	98,121	31,496	32.1
Operating Expenses	17,533	20,532	(2,999)	(14.6)
Asset Impairment Charge	--	19,740	(19,740)	--
Depreciation and Amortization	9,634	9,684	(50)	(0.5)
Operating Income (Loss)	$ 13,702	$ (17,197)	$ 30,899	179.7

The increase in revenues in our Manufacturing segment relates to the following:

Revenues at BTD increased $34.1 million as a result of higher sales volume due to improved customer demand for products and services.

Revenues at ShoreMaster increased $4.2 million mainly as a result of increased sales of both residential and commercial products due to improving dealer confidence and expanded distribution.

Revenues at T.O. Plastics increased by $1.3 million due to increased sales of horticultural and industrial products.

The increase in cost of goods sold in our Manufacturing segment relates to the following:

Cost of goods sold at BTD increased $27.0 million mainly as a result of increased sales volume.

Cost of goods sold at ShoreMaster increased $3.2 million related to an increase in product sales.

Cost of goods sold at T.O. Plastics increased $1.3 million as a result of the increase in sales of horticultural and industrial products and lower productivity.

The net decrease in operating expenses in our Manufacturing segment is due to the following:

Operating expenses at BTD increased $1.3 million mainly due to increased salary and benefit costs related to workforce expansion.

Operating expenses at ShoreMaster decreased $4.7 million, reflecting a $2.7 million increase to its allowance for doubtful accounts in the first nine months of 2010, a $0.6 million decrease to its allowance for doubtful accounts in the first nine months of 2011, a $0.7 million decrease in sales and marketing expenses, a $0.4 million decrease in benefit expenses and a $0.2 million gain on the sale of fixed assets in the first nine months of 2011.

Operating expenses at T.O. Plastics increased $0.2 million due to increased salary and benefit costs.

ShoreMaster recorded a $19.7 million asset impairment charge in the second quarter of 2010. In light of ongoing economic uncertainty and delayed economic recovery, ShoreMaster revised its sales and operating cash flow projections downward in the second quarter of 2010, which resulted in a reassessment of the carrying value of its recorded goodwill. The fair value determination indicated ShoreMaster's goodwill and other intangible assets were 100% impaired and its long-lived assets were partially impaired.

Construction

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 139,895	$ 84,808	$ 55,087	65.0
Cost of Goods Sold	129,137	75,849	53,288	70.3
Operating Expenses	9,184	9,294	(110)	(1.2)
Depreciation and Amortization	1,463	1,466	(3)	(0.2)
Operating Income (Loss)	$ 111	$ (1,801)	$ 1,912	106.2

The increase in revenues in our Construction segment relates to the following:

Revenues at Foley Company increased $54.3 million due to an increase in the magnitude and volume of jobs in progress.

Revenues at Aevenia increased $0.8 million mainly due to increased revenue from electrical and data wiring work.

The increase in cost of goods sold in our Construction segment relates to the following:

Cost of goods sold at Foley Company increased $51.7 million, mainly in the areas of material and subcontractor costs related to the increase in Foley's work volume between the periods.

Cost of goods sold at Aevenia increased $1.6 million between the periods, mainly in labor and material costs, as a result of increased construction activity.

Plastics

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 99,082	$ 76,562	$ 22,520	29.4
Cost of Goods Sold	82,896	66,710	16,186	24.3
Operating Expenses	4,413	4,028	385	9.6
Depreciation and Amortization	2,518	2,417	101	4.2
Operating Income	$ 9,255	$ 3,407	$ 5,848	171.6

Operating revenues for the Plastics segment increased as result of 13.3% increase in pounds of pipe sold combined with a 14.2% increase in the price per pound of pipe sold. The increase in costs of goods sold was due to the increase in pounds of pipe sold combined with a 9.6% increase in the cost per pound of pipe sold. The increase in operating expenses is mostly due to an increase in commissions paid to independent sales representatives.

Health Services

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Operating Revenues	$ 67,331	$ 73,116	$ (5,785)	(7.9)
Cost of Goods Sold	44,899	55,590	(10,691)	(19.2)
Operating Expenses	13,761	13,115	646	4.9
Depreciation and Amortization	6,025	4,050	1,975	48.8
Operating Income	$ 2,646	$ 361	$ 2,285	633.0

Revenues from scanning and other related services decreased $5.3 million due to a 11.3% decrease in scans performed, reflecting the planned discontinuance of portable x-ray services, partially offset by a 6.0% increase in revenue per scan. Revenues from equipment sales decreased $0.5 million. The decrease in cost of goods sold includes a $1.9 million reduction in materials, service labor and repairs and maintenance costs and an $8.6 million reduction in equipment rental costs directly related to efforts by the Health Services segment to right-size its fleet of imaging assets by exercising purchase options on productive imaging assets coming off lease and not renewing leases on underutilized imaging assets. The increase in operating expenses reflects a $0.7 million gain on the sale of fixed assets in the first nine months of 2010. No comparable gain was recorded in the first nine months of 2011. The increase in depreciation expense reflects an increase in owned equipment compared with a year ago.

Corporate

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

(in thousands)	Nine Months Ended September 30, 2011	2010	Change	% Change
Operating Expenses	$ 11,380	$ 11,331	$ 49	0.4
Depreciation and Amortization	415	397	18	4.5

Interest Charges

Interest charges decreased $0.4 million in the first nine months of 2011 compared with the first nine months of 2010 as a result of a $19.4 million decrease in the average balance of short-term debt and current maturities of long-term debt outstanding between the periods, due in part to the pay down of borrowings under our line of credit facility from proceeds from the sale of IPH in May 2011.

Other Income

Other income increased $1.0 million in the first nine months of 2011 compared with the first nine months of 2010 as a result of a $0.6 million increase in allowance for equity funds used during construction at OTP and a $0.4 million decrease in foreign currency transaction losses in the Canadian operations of DMI between the periods.

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Income Taxes – Continuing Operations

(in thousands)	Nine Months Ended September 30, 2011	2010	Variance
Income (Loss) Before Income Taxes – Continuing Operations	$ 22,700	$ (15,379)	$ 38,079
Income Tax Expense (Benefit) - Continuing Operations	4,194	(6,625)	10,819
Effective Income Tax Rate – Continuing Operations	18.5 %	43.1 %	

The increase in Income Tax Expense (Benefit) - Continuing Operations for the nine months ended September 30, 2011 compared with the nine months ended September 30, 2010 is mainly due to the increase in income before income taxes between the periods. Also, only $2.8 million of ShoreMaster's $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes and DMI has deferred recognition of tax benefits in the first nine months of 2011 on the operating losses of its Canadian wind tower manufacturing company until those operations become profitable. DMI's 2011 deferred tax benefits totaled $2.4 million through September 30, 2011. Our effective income tax rates for the nine months ended September 30, 2011 and 2010 were decreased as a result of recording $5.3 million and $4.7 million, respectively, in federal PTCs earned on kwhs generated from tax credit qualified wind turbines owned by OTP. Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes.

Discontinued Operations

The results of operations of IPH and of Wylie's wind turbine component transport business are reported as discontinued operations in our consolidated statements of income for the nine months ended September 30, 2011 and 2010 as summarized in the table below:

	Nine Months Ended September 30, 2011			September 30, 2010		
(in thousands)	IPH	Wylie-Wind	Total	IPH	Wylie-Wind	Total
Operating Revenues	$28,125	$5,448	$33,573	$56,648	$4,700	$61,348
Income (Loss) Before Income Taxes	$3,840	$(4,650)	$(810)	$8,306	$129	$8,435
Gain on Disposition - Pretax	16,011	--	16,011	--	--	--
Income Tax Expense (Benefit)	4,675	(1,860)	2,815	3,029	52	3,081
Net Income (Loss)	$15,176	$(2,790)	$12,386	$5,277	$77	$5,354

FINANCIAL POSITION

The following table presents the status of our lines of credit as of September 30, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on September 30, 2011	Restricted due to Outstanding Letters of Credit	Available on September 30, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$200,000	$20,000	$1,374	$178,626	$144,350

OTP Credit Agreement	170,000	19,010	1,050	149,940	144,436
Total	$370,000	$39,010	$ 2,424	$328,566	$288,786

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings, and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. On March 17, 2010, we entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. Equity or debt financing will be required in the period 2011 through 2015 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our dividend payout ratio has exceeded 100% in each of the last three years. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share to levels in excess of the indicated annual dividend per share of $1.19, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects. The decision to declare a quarterly dividend is reviewed quarterly by the Board of Directors.

DMI is party to a $40 million receivable sales agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement is subject to renewal in March 2012. The current discount rate is 3-month LIBOR plus 4%. Accounts receivable totaling $48.8 million were sold in the first nine months of 2011. Discounts, fees and commissions charged to operating expense for the nine months ended September 30, 2011 and 2010 were $406,000 and $152,000, respectively. The balance of receivables sold that was outstanding to the buyer as of September 30, 2011 was $20.4 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

Cash provided by operating activities from continuing operations was $78.0 million for the nine months ended September 30, 2011 compared with cash provided by operating activities from continuing operations of $56.9 million for the nine months ended September 30, 2010. Cash provided by operating activities from continuing operations was $21.1 million more in the nine months ended September 30, 2011 than in the nine months ended September 30, 2010 mainly as a result of the $20 million discretionary contribution made to our pension plan in September 2010.

Net cash used in investing activities of continuing operations was $68.0 million for the nine months ended September 30, 2011 compared to $60.3 million for the nine months ended September 30, 2010. The $7.7 million increase in cash used for investing activities includes a $13.5 million increase in cash used for capital expenditures at OTP, offset by a $3.5 million reduction in capital expenditures at our nonelectric companies and a $1.9 million decrease in cash used for other investments between the periods. The increase in capital expenditures at OTP is mainly related to expenditures for the Bemidji to Grand Rapids and Fargo to St. Cloud CapX2020 transmission line construction projects.

Net cash used in financing activities from continuing operations increased $80.3 million in the nine months ended September 30, 2011 compared with the nine months ended September 30, 2010 mainly due to a $82.9 million decrease in short-term borrowings and checks issued in excess of cash, net of a decrease in cash used to retire long-term debt between the periods. We paid $59.2 million to retire long-term debt in the first nine months of 2010 but increased short-term borrowings by $86.4 million over the same period. Cash used to repay short-term borrowings and checks written in excess of cash totaled $50.4 million in the first nine months of 2011. The cash used to pay down short-term debt in the first nine months of 2011 came from $84.3 million in net proceeds from the sale of IPH in May 2011.

Our contractual obligations reported in the table on page 56 of our Annual Report on Form 10-K for the year ended December 31, 2010 have increased by $45.0 million: Our “Capacity and Energy Requirements” have increased by $1.1 million for 2011, $8.8 million for 2012 and 2013, and $15.9 million for 2014 and 2015 related to long-term power purchase agreements entered into with a regional generator and supplier in the first quarter of 2011. Our “Coal Contracts (required minimums)” have increased by $5.7 million in 2011 and $13.5 million in 2012 related to an expansion and extension of an agreement to supply coal to OTP’s Hoot Lake Plant.

On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement.

On March 17, 2010, we entered into a Distribution Agreement (the Agreement) with JPMS. Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75 million. Under the Agreement, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to our shelf registration statement, as amended. No shares have been sold pursuant to the Agreement.

On May 4, 2010 we entered into a $200 million Second Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement) with the Banks named therein, which is an unsecured revolving credit facility that we can draw on to support our nonelectric operations. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on our senior unsecured credit ratings. The Otter Tail Corporation Credit Agreement expires on May 4, 2013. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of Varistar Corporation (Varistar), our wholly owned subsidiary, and its material subsidiaries, including restrictions on our and their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default. The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our material subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Otter Tail Corporation Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Otter Tail Corporation Credit Agreement.

On March 3, 2011 OTP entered into an Amended and Restated Credit Agreement (the OTP Credit Agreement) with the Banks named therein. The OTP Credit Agreement provides for a $170 million line of credit that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under the line of credit currently bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. Under the OTP Credit Agreement OTP is required to pay the Banks’ commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement expires on March 3, 2016.

The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The OTP Credit Agreement amends and restates the $170 million Credit Agreement dated as of July 30, 2008 among OTP (formerly known as Otter Tail Corporation, dba Otter Tail Power Company), the Banks named therein, as amended by a First Amendment to Credit Agreement dated as of April 21, 2009 and a Second Amendment to Credit Agreement dated as of June 22, 2009.

On March 18, 2011 we borrowed $1.5 million under a Partnership in Assisting Community Expansion loan to finance capital investments at Northern Pipe Products, Inc. (NPP), our polyvinyl chloride (PVC) pipe manufacturing subsidiary located in Fargo, North Dakota. The ten-year unsecured note bears interest at 2.54% with monthly principal and interest payments through March 2021. On April 6, 2011 we borrowed $0.5 million under a North Dakota Development Fund loan to finance additional capital investments at NPP. The seven-year unsecured note bears interest at 3.95% with monthly principal and interest payments through April 1, 2018.

On July 29, 2011, OTP entered into a Note Purchase Agreement (the 2011 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP has agreed to issue to the purchasers in a private placement transaction $140 million aggregate principal amount of OTP’s 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes). The 2021 Notes are expected to be issued on December 1, 2011, subject to the satisfaction of certain customary conditions to closing. OTP intends to use a portion of the proceeds of the 2021 Notes to retire $90 million aggregate principal amount of OTP’s 6.63% Senior Notes due December 1, 2011 (the 2011 Notes) and $10.4 million aggregate principal amount of its pollution control refunding revenue bonds due December 1, 2012. The 2011 Notes remain classified as long-term debt because OTP has made arrangements to refinance this debt with borrowings under the 2011 Note Purchase Agreement.

The note purchase agreement relating to the 2011 Notes, as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to our $50 million 8.89% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), the note purchase agreement relating to OTP’s $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, as amended (the 2007 Note Purchase Agreement) and the 2011 Note Purchase Agreement each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement, the 2001 Note Purchase Agreement and the 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement, the Cascade Note Purchase Agreement and the 2011 Note Purchase Agreement each contains a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor’s ability and the ability of the obligor’s subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Our obligations under the Cascade Note Purchase Agreement are guaranteed by certain of our material subsidiaries. Cascade owned approximately 9.6% of the Company’s outstanding common stock as of December 31, 2010.

On June 23, 2010 we entered into Amendment No. 3 to the Cascade Note Purchase Agreement. Amendment No. 3 amends certain covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide us and our material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 we entered into Amendment No. 4 to the Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit us to exclude impairment charges and write-offs of assets from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement.

Financial Covenants

As of September 30, 2011 the Company and OTP were each in compliance with the financial statement covenants that existed in their respective debt agreements.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Our and OTP's borrowing agreements require us and OTP, respectively, to comply with certain financial covenants, and upon the issuance of the 2021 Notes, the 2011 Note Purchase Agreement will require OTP to comply with similar covenants. Specifically:

- Under the Otter Tail Corporation Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement. As of September 30, 2011 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement was 1.78 to 1.00.

- Under the Cascade Note Purchase Agreement, we may not permit our ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or our Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement. As of September 30, 2011 our Interest Charges Coverage Ratio calculated under the requirements of the Cascade Note Purchase Agreement was 1.66 to 1.00.

- Under the OTP Credit Agreement and, upon the issuance of the 2021 Notes, under the 2011 Note Purchase Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the related agreement. As of September 30, 2011 OTP's Interest and Dividend Coverage Ratio calculated under the requirements of each such agreement was 3.33 to 1.00.

- Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and, upon the issuance of the 2021 Notes, under the 2011 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of September 30, 2011 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of each such agreement was 3.33 to 1.00.

As of September 30, 2011 our interest-bearing debt to total capitalization was 0.43 to 1.00 on a fully consolidated basis and 0.48 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $10.1 million, but our line of credit borrowing limits are only restricted by $2.4 million of the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2011 BUSINESS OUTLOOK

The following updated guidance considers the cyclical nature of some of our businesses and reflects challenges presented by current economic conditions and our plans and strategies for improving future operating results.

Our updated 2011 earnings per share guidance range is as follows:

2011 Earnings Per Share Guidance Range

	Previous Guidance		Current Guidance	
	Low	High	Low	High
Electric	$ 1.01	$ 1.06	$ 1.05	$ 1.10
Wind Energy	(.80)	(.50)	(.70)	(.55)
Manufacturing	.25	.30	.23	.28
Construction	.05	.08	.00	.03
Plastics	.10	.13	.12	.15
Health Services	.01	.05	.01	.05
Corporate	(.20)	(.18)	(.23)	(.21)
Total – Continuing Operations	$ .42	$ .94	$ .48	$ .85
Earnings – Discontinued Operations:				
IPH	.07	.07	.07	.07
E.W. Wylie Wind-Heavy Haul	(.12)	(.08)	(.10)	(.08)
Gain on Sale of IPH	.35	.37	.32	.35
Total	$ .72	$ 1.30	$ .77	$ 1.19

Contributing to our earnings guidance for 2011 are the following items:

- We expect an increase in net income from our Electric segment over our previous guidance and for 2011 compared to 2010. This is based on sales growth, rate and rider recovery increases and an increase in capitalized interest costs related to larger construction expenditures along with stable operating and maintenance expenses in 2011 compared with 2010.

- Our 2011 earnings guidance for our Wind Energy segment reflects the following factors:

o While DMI has been able to stabilize production, improve productivity, align headcount with the year's remaining production demands and eliminate the need for outsourced quality assurance staffing, we expect a 2011 loss primarily as a result of the challenges faced in the first half of the year. In spite of soft demand in the wind industry, order backlog has solidified for the remainder of 2011 supporting full load of current plant staffing at DMI's Tulsa and West Fargo plants. DMI continues to experience increased pricing pressure on new orders due to overcapacity in the U.S. market and significantly lower steel costs available to Asian manufacturers. Potential exposure to liquidated damages, warranty claims, or remediation costs related to past production issues remain.

o We exited Wylie's wind-heavy haul business in the second quarter of 2011. Accordingly, the results of operations from this part of the business have been reclassified to discontinued operations. We expect the continuing flatbed trucking operations to record a loss in 2011 given the net loss that occurred in the third quarter, which is not expected to be recovered from fourth quarter operating results. This current operating loss could be an indicator of lower-than-expected future profitability and could result in reductions in anticipated future cash flows from transportation operations, which may indicate the fair value of Wylie is less than its carrying value. While not reflected in current guidance, this could result in a future impairment and corresponding charge against earnings of all or a portion of the $6.7 million of goodwill recorded on our balance sheet related to the acquisition of Wylie. We continue to explore remedies to maximize the performance and value of this business.

- o Backlog in the Wind Energy segment is $33 million for 2011 compared with $23 million one year ago.

- We expect earnings from our Manufacturing segment to decrease from our previous guidance based on third quarter results being below expectations. However, we still expect an increase from our original 2011 guidance as a result of increased order volume and continuing improvement in economic conditions in the industries BTD serves. We are expecting significantly improved performance at ShoreMaster as a result of bringing costs in line with current revenue levels and absent last year's $15.6 million net-of-tax noncash impairment charge. We expect T.O. Plastics to have earnings at the same level as 2010. Backlog for the manufacturing companies is approximately $34 million for 2011 compared with $33 million one year ago.

- We expect slightly higher net income from our Construction segment in 2011 as the economy improves and the construction companies record earnings on a higher volume of jobs in progress. The reduction in guidance from the previous quarter relates to cost overruns on a Foley project that contributed to a $0.6 million reduction in net income at Foley Company in the third quarter, along with continued poor performance on construction contracts at Aevenia. Backlog for the construction businesses is $47 million for 2011 compared with $48 million one year ago.

- We are increasing our earnings expectations for our Plastics segment given its strong 2011 year-to-date performance.

- We still expect an increase in earnings from our Health Services segment in 2011 compared with 2010 as the benefits of implementing its asset reduction plan continue to be realized. Significant improvements have been made in the utilization of its fleet through a better mix of assets and cost reductions. However, our Health Services business continues to operate in a difficult economic environment with much uncertainty about the health care industry. Although not factored into current guidance, continued economic recovery concerns and the recent negative impact the stock markets have had on market capitalizations of certain publicly traded companies in this sector could be an indication the fair value of our Health Services segment is less than its carrying value. This could result in a future impairment and corresponding charge against earnings of all or a portion of the $23.7 million of goodwill recorded on our balance sheet related to acquisitions of our Health Services businesses. We continue to evaluate strategies to maximize the performance and value of this business.

- Our expectations for corporate general and administrative cost have been revised upward as a result of the incurrence of termination benefits related to the resignation of our chief executive officer in the third quarter of 2011, but overall 2011 expenses are still expected to be less than 2010 expenses as a result of reductions in employee count and associated decreases in benefit costs.

- The net earnings and the gain on sale of IPH are reflective of the actual results as the sale of the business closed in May 2011. In addition, we exited the wind-heavy haul operations of Wylie in the second quarter of 2011. The net loss reflected in the guidance table is the result of actual operating activity of this business and an estimate of any other potential costs that could occur as the business winds down. There was no gain or loss incurred on disposal of the asset fleet associated with Wylie's wind-heavy haul business.

The sale of IPH was a strategic decision by management to monetize a currently strong earning asset and use the proceeds to pay down short-term borrowings. This frees up liquidity going forward for upcoming Electric segment capital investments and helps ease the need to rely on the capital markets to fully fund these expenditures. We will continue to review our portfolio to see where additional opportunities exist to improve our risk profile, improve credit metrics and generate additional sources of cash to support the future capital expenditure plans of our Electric segment. Future IPH earnings forfeited through the sale of IPH are expected to be replaced by increased utility earnings as the utility makes investments in its current capital plan. This will result in a larger percentage of our earnings coming from our most stable and relatively predictable business, OTP, and is consistent with the strategy to grow this business given its current investment opportunities.

We currently anticipate the following capital expenditures and electric utility average rate base for 2011 through 2015:

(in millions)	2011	2012	2013	2014	2015
Capital Expenditures:					
Electric Segment:					
Transmission	$ 23	$ 31	$ 65	$ 48	$ 22
Environmental	4	49	97	80	40
Other	40	50	57	54	64
Total Electric Segment	$ 67	$ 130	$ 219	$ 182	$ 126
Nonelectric Segments	40	41	48	44	43
Total Capital Expenditures	$ 107	$ 171	$ 267	$ 226	$ 169
Total Electric Utility Average Rate Base	$ 651	$ 722	$ 876	$ 1,057	$ 1,299

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2011 through 2015 timeframe. We intend to maintain an equity to total capitalization ratio near its present level of 51% in our Electric segment and will seek to earn our authorized overall return on equity of approximately 10.5% in the utility's regulatory jurisdictions.

Regarding the collective operating companies in our nonelectric segments, there is a general expectation that business will strengthen in 2012 and 2013, as the U.S. economy slowly recovers. This is expected to lead to increased demand for our industrial products and services, generating higher revenues. This expectation, coupled with cost reductions that have taken place across our company, should result in rising earnings per share for our nonelectric businesses as a whole.

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts, contingent liabilities, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption "Critical Accounting Policies Involving Significant Estimates" on pages 61 through 64 of our Annual Report on Form 10-K for the year ended December 31, 2010. There were no material changes in critical accounting policies or estimates during the quarter ended September 30, 2011.

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

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

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

- We are subject to federal and state legislation, regulations and actions that may have a negative impact on our business and results of operations.

- Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.
- Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and could increase borrowing costs and pension plan and postretirement health care expenses.
- We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are not able to access capital at competitive rates, our ability to implement our business plans may be adversely affected.

- We may, from time to time, sell one or more of our nonelectric businesses to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any business sold.

- We may experience fluctuations in revenues and expenses related to our operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to our shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

- Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of our customers to finance purchases of goods and services, and our financial condition, as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

- We are not currently required to make any contributions to our defined benefit pension plan in 2011. We could make discretionary contributions to the plan or could be required to contribute additional capital to the pension plan in future years if the market value of pension plan assets significantly declines in the future, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

- Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.

- A sustained decline in our common stock price below book value or declines in projected operating cash flows at any of our operating companies may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

- The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on us.

- Economic conditions could negatively impact our businesses.

- If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

- Our plans to grow and realign our diversified business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

- Our plans to grow and operate our nonelectric businesses could be limited by state law.

- Our subsidiaries enter into production and construction contracts, including contracts for new product designs, which could expose them to unforeseen costs and costs not within their control, which may not be recoverable and could adversely affect our results of operations and financial condition.

- Significant warranty claims in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition. Also, expenses associated with remediation activities in the Wind Energy segment could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If we are required to cover remediation expenses in addition to regular warranty coverage, we could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect our consolidated results of operations and financial condition.

- We are subject to risks associated with energy markets.
- We are subject to risks and uncertainties related to the timing and recovery of deferred tax assets which could have a negative impact on our net income in future periods.
- Certain of our operating companies sell products to consumers that could be subject to recall.
- Competition is a factor in all of our businesses.
- Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

- OTP could be required to absorb a disproportionate share of costs for investments in transmission infrastructure required to provide independent power producers access to the transmission grid. These costs may not be recoverable through a transmission tariff and could result in reduced returns on invested capital and/or increased rates to OTP's retail electric customers.

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

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

- Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO2) emissions, could affect OTP’s operating costs and the costs of supplying electricity to its customers.

- The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact our results of operations and growth.

- Our wind tower manufacturing business is substantially dependent on a few significant customers.

- Prolonged periods of low utilization of DMI’s wind tower production plants, due to a continuing softening of demand for its product, could cause DMI to idle certain facilities. Should this softened demand for wind towers continue, these events may result in impairment charges on certain of DMI’s facilities if future cash flow estimates, based on information available to management at the time, indicate that the plants carrying values may not be recoverable or, if any plant assets are sold below their carrying values, significant losses may be incurred.

- Competition from foreign and domestic manufacturers, cost management in a fixed price contract project environment, the price and availability of raw materials and diesel fuel, the ability of suppliers to deliver materials at contracted prices, fluctuations in foreign currency exchange rates and general economic conditions could affect the revenues and earnings of our wind energy and manufacturing businesses.

- A significant failure or an inability to properly bid or perform on projects by our wind energy, construction or manufacturing businesses could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

- Our Plastics segment is highly dependent on a limited number of vendors for PVC resin, many of which are located in the Gulf Coast regions, and a limited supply of resin. The loss of a key vendor, or an interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for this segment.

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

- Reductions in PVC resin prices can negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

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

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

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At September 30, 2011 we had exposure to market risk associated with interest rates because we had $20.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 3.25% under our $200 million revolving credit facility and $19.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.5% under OTP's $170 million revolving credit facility. At September 30, 2011 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of September 30, 2011 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on September 30, 2011, annualized interest expense and pre-tax earnings would change by approximately $104,000.

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

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

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

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of September 30, 2011 OTP had recognized, on a pretax basis, $974,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase and sales contracts that are marked to market as of September 30, 2011 are 97% offsetting in terms of volumes and delivery periods but not in terms of delivery points.

The differential in forward prices at the different delivery locations currently results in a mark-to-market unrealized gain on OTP's open forward contracts.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of September 30, 2011 because the open purchases were not at the same delivery points as the open sales.

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 our consolidated balance sheets as of September 30, 2011 and December 31, 2010, and the change in our consolidated balance sheet position from December 31, 2010 to September 30, 2011:

(in thousands)	September 30, 2011	December 31, 2010
Other Current Assets – Marked-to-Market Gain	$ 3,929	$ 6,875
Regulatory Assets – Deferred Marked-to-Market Loss	13,560	12,054
Total Assets	17,489	18,929
Derivative Liabilities – Marked-to-Market Loss	(16,390)	(17,991)
Regulatory Liabilities – Deferred Marked-to-Market Gain	(125)	(175)
Total Liabilities	(16,515)	(18,166)
Net Fair Value of Marked-to-Market Energy Contracts	$ 974	$ 763

(in thousands)	Year-to-Date September 30, 2011
Fair Value at Beginning of Year	$ 763
Less: Amounts Realized on Contracts Entered into in 2009 and Settled in 2011	(225)
Amounts Realized on Contracts Entered into in 2010 and Settled in 2011	(28)
Changes in Fair Value of Contracts Entered into in 2009 in 2011	(14)
Changes in Fair Value of Contracts Entered into in 2010 in 2011	(72)
Net Fair Value of Contracts Entered into in 2009 and 2010 at End of Period	424
Changes in Fair Value of Contracts Entered into in 2011	550
Net Fair Value End of Period	$ 974

The $974,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on September 30, 2011 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	4th Quarter 2011	2012	Total
Net Gain	$ 354	$ 620	$ 974

The following realized and unrealized net gains on forward energy contracts are included in electric operating revenues on our consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2011	2010	2011	2010
Net Gains on Forward Electric Energy Contracts	$ 456	$ 144	$ 587	$ 1,945

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of September 30, 2011 was $372,000. As of September 30, 2011 OTP had a net credit risk exposure of $792,000 from five counterparties with investment grade credit ratings. OTP had no exposure at September 30, 2011 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 $792,000 credit risk exposure included net amounts due to OTP 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 September 30, 2011. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of September 30, 2011, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2011.

During the fiscal quarter ended September 30, 2011, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

The Company is updating the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 32 through 39 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, as updated in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 under Part II, Item 1A, "Risk Factors" to add the following risk factor:

We may, from time to time, sell one or more of our nonelectric businesses to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any business sold.

As part of our business strategy, we intend to realign our business portfolio by divesting of some of our nonelectric businesses and building our electric utility's earnings base in order to lower our overall risk. A loss on the sale of a business would be recognized if a company is sold for less than its book value.

Item 6. Exhibits

4.1 Note Purchase Agreement dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on August 3, 2011).

10.1 Nonqualified Retirement Savings Plan (2011 Restatement).

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

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

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

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101.INS XBRL Instance Document.

101.SCH XBRL Taxonomy Extension Schema Document.

101.CAL XBRL Taxonomy Extension Calculation Linkbase Document.

101.LAB XBRL Taxonomy Extension Label Linkbase Document.

101.PRE XBRL Taxonomy Extension Presentation Linkbase Document.

101.DEF XBRL Taxonomy Extension Definition Linkbase Document.

SIGNATURES

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

OTTER TAIL CORPORATION

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

Dated: November 9, 2011

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