Otter Tail Corp
Form 10-Q
May 10, 2012

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 March 31, 2012

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. (Check one):

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:

April 30, 2012 – 36,163,773 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)	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$14,652
Accounts Receivable:		
Trade—Net	139,350	116,522
Other	16,019	18,807
Inventories	82,959	77,983
Deferred Income Taxes	12,335	12,307
Accrued Utility Revenues	12,150	13,719
Costs and Estimated Earnings in Excess of Billings	66,394	67,109
Regulatory Assets	24,980	27,391
Other	20,867	21,414
Assets of Discontinued Operations	529	29,692
Total Current Assets	375,583	399,596
Investments	11,337	11,093
Other Assets	27,812	26,997
Goodwill	39,406	39,406
Other Intangibles—Net	15,038	15,286
Deferred Debits		
Unamortized Debt Expense	6,125	6,458
Regulatory Assets	122,481	124,137
Total Deferred Debits	128,606	130,595
Plant		
Electric Plant in Service	1,378,651	1,372,534
Nonelectric Operations	309,565	310,320
Construction Work in Progress	63,469	54,439
Total Gross Plant	1,751,685	1,737,293
Less Accumulated Depreciation and Amortization	670,349	659,744
Net Plant	1,081,336	1,077,549
Total Assets	$1,679,118	$1,700,522

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	March 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$3,311	$--
Current Maturities of Long-Term Debt	3,000	3,033
Accounts Payable	121,518	115,514
Accrued Salaries and Wages	14,279	19,043
Accrued Taxes	12,149	11,841
Derivative Liabilities	24,686	18,770
Other Accrued Liabilities	7,842	5,540
Liabilities of Discontinued Operations	37	13,763
Total Current Liabilities	186,822	187,504
Pensions Benefit Liability	97,719	106,818
Other Postretirement Benefits Liability	49,013	48,263
Other Noncurrent Liabilities	26,670	19,002
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	161,041	177,264
Deferred Tax Credits	32,868	33,182
Regulatory Liabilities	69,003	69,106
Other	540	520
Total Deferred Credits	263,452	280,072
Capitalization		
Long-Term Debt, Net of Current Maturities	471,878	471,915
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2012 and 2011 – 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, 2012—36,107,795 Shares; 2011—36,101,695 Shares	180,539	180,509
Premium on Common Shares	253,267	253,123
Retained Earnings	137,566	141,248
Accumulated Other Comprehensive Loss	(3,308)	(3,432)
Total Common Equity	568,064	571,448

Total Capitalization	1,055,442	1,058,863
Total Liabilities and Equity	$1,679,118	$1,700,522

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended March 31, 2012	2011
Operating Revenues		
Electric	$89,938	$91,526
Nonelectric	187,651	157,622
Total Operating Revenues	277,589	249,148
Operating Expenses		
Production Fuel - Electric	15,424	19,577
Purchased Power - Electric System Use	14,158	12,377
Electric Operation and Maintenance Expenses	30,013	28,708
Asset Impairment Charge - Electric	432	--
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	162,990	140,339
Other Nonelectric Expenses	17,491	13,076
Depreciation and Amortization	17,053	17,106
Property Taxes - Electric	2,617	2,409
Total Operating Expenses	260,178	233,592
Operating Income	17,411	15,556
Interest Charges	8,616	9,476
Other Income	993	371
Income from Continuing Operations Before Income Taxes	9,788	6,451
Income Taxes – Continuing Operations	297	1,238
Net Income from Continuing Operations	9,491	5,213
Discontinued Operations		
Income - net of Income Tax Expense of $584 and $288 for the respective periods	841	483
Loss on Disposition - net of Income Tax Benefit of ($134) in 2012	(3,089)	--
Net (Loss) Income from Discontinued Operations	(2,248)	483
Net Income	7,243	5,696
Preferred Dividend Requirements	184	184
Earnings Available for Common Shares	$7,059	$5,512
Average Number of Common Shares Outstanding—Basic	35,995,179	35,876,853
Average Number of Common Shares Outstanding—Diluted	36,129,192	36,081,426
Basic Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement)	$0.26	$0.14
Discontinued Operations	(0.06)	0.01
	0.20	0.15
Diluted Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement)	$0.26	$0.14
Discontinued Operations	(0.06)	0.01

	0.20	0.15
Dividends Declared Per Common Share	$0.2975	$0.2975

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Comprehensive Income
(not audited)

(in thousands)	Three Months Ended March 31, 2012	2011
Net Income	$7,243	$5,696
Other Comprehensive (Loss) Income:		
Unrealized Gain (Loss) on Available-for-Sale Securities:		
Gain (Loss) Arising During Period	104	(17)
Income Tax (Expense) Benefit	(41)	7
Gain (Loss) on Available-for-Sale Securities – net-of-tax	63	(10)
Foreign Currency Translation Adjustment Gain:		
Unrealized Net Change During Period	--	645
Income Tax Expense	--	(200)
Foreign Currency Translation Adjustment Gain – net-of-tax	--	445
Pension and Postretirement Benefit Plans:		
Actuarial Loss -- Regulatory Allocation Adjustment (ESSRP)	--	(1,621)
Amortization of Unrecognized Postretirement Benefit Losses and Costs	102	171
Income Tax (Expense) Benefit	(41)	580
Pension and Postretirement Benefit Plans – net-of-tax	61	(870)
Total Other Comprehensive Income (Loss)	124	(435)
Total Comprehensive Income	$7,367	$5,261

See accompanying notes to consolidated financial statements.

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

(in thousands)	Three Months Ended March 31, 2012	2011
Cash Flows from Operating Activities		
Net Income	$7,243	$5,696
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Loss from Sale of Discontinued Operations	3,089	--
Income from Discontinued Operations	(841)	(483)
Depreciation and Amortization	17,053	17,106
Asset Impairment Charge	432	--
Deferred Tax Credits	(522)	(659)
Deferred Income Taxes	(7,717)	4,124
Change in Deferred Debits and Other Assets	7,872	6,266
Discretionary Contribution to Pension Plan	(10,000)	--
Change in Noncurrent Liabilities and Deferred Credits	9,299	85
Allowance for Equity (Other) Funds Used During Construction	(162)	(116)
Change in Derivatives Net of Regulatory Deferral	281	(59)
Stock Compensation Expense – Equity Awards	287	452
Other—Net	321	304
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(20,040)	(30,390)
Change in Inventories	(4,976)	(1,675)
Change in Other Current Assets	(3,034)	(634)
Change in Payables and Other Current Liabilities	5,598	1,873
Change in Interest and Income Taxes Receivable/Payable	2,251	1,245
Net Cash Provided by Continuing Operations	6,434	3,135
Net Cash Provided by Discontinued Operations	1,417	3,826
Net Cash Provided by Operating Activities	7,851	6,961
Cash Flows from Investing Activities		
Capital Expenditures	(36,321)	(20,596)
Proceeds from Disposal of Noncurrent Assets	1,824	258
Net Increase in Other Investments	(1,321)	(598)
Net Cash Used in Investing Activities - Continuing Operations	(35,818)	(20,936)
Net Proceeds from Sale of Discontinued Operations	24,362	--
Net Cash Used in Investing Activities - Discontinued Operations	(11,705)	(2,522)
Net Cash Used in Investing Activities	(23,161)	(23,458)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	10,546	(8,463)
Net Short-Term Borrowings	3,311	37,486
Proceeds from Issuance of Long-Term Debt	--	1,500
Short-Term and Long-Term Debt Issuance Expenses	(10)	(686)
Payments for Retirement of Long-Term Debt	(70)	(70)
Dividends Paid and Other Distributions	(11,037)	(11,041)
Net Cash Provided by Financing Activities - Continuing Operations	2,740	18,726
Net Cash Used in Financing Activities - Discontinued Operations	(1,409)	(1,502)

Net Cash Provided by Financing Activities	1,331	17,224
Net Change in Cash and Cash Equivalents - Discontinued Operations	(673)	1,145
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	--	(288)
Net Change in Cash and Cash Equivalents	(14,652)	1,584
Cash and Cash Equivalents at Beginning of Period	14,652	--
Cash and Cash Equivalents at End of Period	$--	$1,584

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, 2011, 2010 and 2009 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011. Because of seasonal and other factors, the earnings for the three months ended March 31, 2012 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, 2011.

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 (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) 815, Derivatives and Hedging. 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 March 31,	
	2012	2011
Percentage-of-Completion Revenues	32.2 %	35.5 %

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

(in thousands)	March 31, 2012	December 31, 2011
Costs Incurred on Uncompleted Contracts	$457,977	$583,346
Less Billings to Date	(421,796)	(550,070)
Plus Estimated Earnings Recognized	22,232	24,478
	$58,413	$57,754

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

(in thousands)	March 31, 2012	December 31, 2011
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$66,394	$67,109
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(7,981)	(9,355)
	$58,413	$57,754

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)	March 31, 2012	December 31, 2011
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts - DMI	$54,199	$54,541

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, 2011	$ 3,170
Provision for Warranties Issued During the Year	325
Settlements Made During the Year	(380)
Adjustments to Warranty Estimates for Prior Years	(38)
Warranty Reserve Balance, March 31, 2012	$ 3,077

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)	March 31, 2012	December 31, 2011
Accounts Receivable Retained by Customers	$13,387	$13,526

Sales of Receivables
DMI was a party to a $40 million receivables sales agreement whereby designated customer accounts receivable were sold to General Electric Capital Corporation on a revolving basis. 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 March 31,	
(in thousands)	2012	2011
Accounts Receivable Sold	$ 21,028	$ 19,048
Discounts, Fees and Commissions Paid on Sale of Accounts Receivable	$ 197	$ 118

This agreement was terminated effective April 26, 2012. DMI has negotiated payment terms with the customer whose receivables were being sold and has agreed to receive accelerated payment of receivables due from the customer in exchange for a negotiated discount for early payment.

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 tables present, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2012 and December 31, 2011:

March 31, 2012 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds	$ 1,264	$ --	
Equity Securities	127		
Forward Gasoline Purchase Contracts		15	

Forward Energy Contracts				5,391
Investments of Captive Insurance Company:				
Money Market Fund		80		
Corporate Debt Securities				7,846
U.S. Government Debt Securities				1,297
Money Market Fund - Escrow Account Idaho Pacific Holdings, Inc. (IPH) Sale		3,001		
Total Assets	$	4,472	$	14,549
Liabilities:				
Forward Gasoline Purchase Contracts	$	--	$	4
Forward Energy Contracts		--		24,682
Total Liabilities	$	--	$	24,686

December 31, 2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds	$ 364	$ --	
Forward Gasoline Purchase Contracts	9		
Forward Energy Contracts		3,803	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		15,957	
Investments of Captive Insurance Company:			
Corporate Debt Securities		8,083	
U.S. Government Debt Securities	707		
Money Market Fund - Escrow Account (IPH) Sale	3,001		
Total Assets	$ 4,081	$ 27,843	
Liabilities:			
Forward Energy Contracts	$ --	$ 18,770	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		96	
Total Liabilities	$ --	$ 18,866	

In 2012, the Company's investments in forward gasoline contracts and U.S. government debt securities were moved to level 2 of the fair value hierarchy and the regulatory assets and liabilities are no longer included in the fair value table.

Inventories

Inventories consist of the following:

(in thousands)	March 31, 2012	December 31, 2011
Finished Goods	$ 24,569	$ 21,373
Work in Process	12,589	11,951
Raw Material, Fuel and Supplies	45,801	44,659
Total Inventories	$ 82,959	$ 77,983

Goodwill and Other Intangible Assets

The following table summarizes changes to goodwill by business segment during 2012:

(in thousands)	Gross Balance December 31, 2011	Accumulated Impairments	Balance (net of impairments) December 31, 2011	Adjustments to Goodwill in 2012	Balance (net of impairments) March 31, 2012
Electric	$240	$ (240)	$ --	$ --	$ --
Wind Energy	288	--	288	--	288
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	--	7,630
Plastics	19,302	--	19,302	--	19,302
Total	$51,905	$ (12,499)	$ 39,406	$ --	$ 39,406

Other Intangible Assets

The following table summarizes the components of the Company's intangible assets at March 31, 2012 and December 31, 2011:

March 31, 2012 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 3,449	$ 13,362	15 – 25 years
Covenants Not to Compete	713	712	1	3 – 5 years
Other Intangible Assets Including Contracts	2,192	517	1,675	5 – 30 years
Total	$ 19,716	$ 4,678	$ 15,038	
December 31, 2011 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 3,236	$ 13,575	15 – 25 years
Covenants Not to Compete	713	709	4	3 – 5 years
Other Intangible Assets Including Contracts	2,192	485	1,707	5 – 30 years
Total	$ 19,716	$ 4,430	$ 15,286	

The amortization expense for these intangible assets was:

	Three Months Ended March 31,	
(in thousands)	2012	2011
Amortization Expense – Intangible Assets	$ 247	$ 224

The estimated annual amortization expense for these intangible assets for the next five years is:

(in thousands)	2012	2013	2014	2015	2016
Estimated Amortization Expense – Intangible Assets	$981	$977	$977	$977	$945

Supplemental Disclosures of Cash Flow Information

	Three Months Ended March 31,	
(in thousands)	2012	2011
(Decrease) Increase in Accounts Payable Related to Capital Expenditures	$ (13,562)	$ 13

Reclassifications and Changes to Presentation

The Company's consolidated income statement and consolidated statement of cash flows for the three months ended March 31, 2011 reflect the reclassifications of the operating results and cash flows of E.W. Wylie Corporation (Wylie), DMS Health Technologies, Inc. (DMS), and Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of ShoreMaster, Inc. (ShoreMaster), to discontinued operations as a result of the December 2011 sale of Wylie, the January 2012 sale of Aviva and the February 2012 sale of DMS. The reclassifications had no impact on the Company's total consolidated net income or cash flows for the three months ended March 31, 2011.

2. Segment Information

The Company's businesses have been classified into five 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 sell products and provide services to customers primarily in the United States. The five segments are: Electric, Wind Energy, Manufacturing, Construction and Plastics.

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 Energy consists of DMI, 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. The facility in Ontario, Canada was idled in the fourth quarter of 2011 due to a lack of orders for wind towers.

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 and Minnesota 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.

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

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).

The Company’s corporate operating costs include 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 one customer within the Wind Energy segment that accounted for 10.8% of the Company’s consolidated revenues in 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 March 31,			
	2012		2011	
United States of America	97.8	%	98.8	%
Canada	1.4	%	1.1	%

All Other Countries (none greater than 1%)	0.8	%	0.1	%

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three months ended March 31, 2012 and amounts restated to reflect continuing operations for the three month periods ended March 31, June 30, and September 30, 2011, and total assets by business segment as of March 31, 2012 and December 31, 2011 are presented in the following tables:

Operating Revenue

	Three Months Ended			
	March 31,		June 30,	September 30,
(in thousands)	2012	2011	2011	2011
Electric	$90,003	$91,596	$78,031	$85,172
Wind Energy	52,102	46,988	55,025	52,595
Manufacturing	65,994	55,361	57,320	55,625
Construction	35,617	37,515	49,133	53,247
Plastics	34,875	18,478	44,373	36,231
Corporate Revenues and Intersegment Eliminations	(1,002)	(790)	(584)	(497)
Total	$277,589	$249,148	$283,298	$282,373

Interest Expense

	Three Months Ended			
	March 31,		June 30,	September 30,
(in thousands)	2012	2011	2011	2011
Electric	$4,851	$5,088	$4,990	$4,796
Wind Energy	1,700	1,701	1,858	1,775
Manufacturing	1,336	1,211	1,255	1,229
Construction	253	220	227	251
Plastics	346	363	402	411
Corporate and Intersegment Eliminations	130	893	406	234
Total	$8,616	$9,476	$9,138	$8,696

Income Taxes

	Three Months Ended			
	March 31,		June 30,	September 30,
(in thousands)	2012	2011	2011	2011
Electric	$1,622	$2,600	$7	$3,364
Wind Energy	(156)	(1,549)	(2,174)	(383)
Manufacturing	1,469	1,790	1,561	781
Construction	(2,776)	(210)	130	(115)
Plastics	2,175	(241)	2,144	1,295
Corporate	(2,037)	(1,152)	(1,753)	(2,560)
Total	$297	$1,238	$(85)	$2,382

Earnings Available for Common Shares

	Three Months Ended			
	March 31,		June 30,	September 30,
(in thousands)	2012	2011	2011	2011
Electric	$11,016	$11,142	$7,386	$10,900
Wind Energy	(690)	(6,232)	(6,566)	(2,770)
Manufacturing	2,211	2,658	2,769	1,366
Construction	(4,171)	(325)	184	(179)
Plastics	3,253	(374)	3,312	1,970
Corporate	(2,312)	(1,840)	(2,144)	(4,135)
Discontinued Operations	(2,248)	483	13,381	(968)
Total	$7,059	$5,512	$18,322	$6,184

Identifiable Assets

(in thousands)	March 31, 2012	December 31, 2011
Electric	$ 1,167,688	$ 1,170,449
Wind Energy	150,400	149,234
Manufacturing	163,855	154,908
Construction	67,288	69,453
Plastics	87,066	72,200
Corporate	42,292	54,586
Discontinued Operations	529	29,692
Total	$ 1,679,118	$ 1,700,522

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, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (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. Final rates went into effect October 1, 2011. The overall increase to customers was approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately $3.9 million in the fourth quarter of 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased 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.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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

The MPUC issued an order on January 12, 2010 finding OTP's Luverne Wind Farm project eligible for cost recovery through the Minnesota Renewable Resource Adjustment (MNRRA). The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the MNRRA to $0.00684 per kilowatt-hour (kwh) plus $0.298 per kiloWatt (kW) for the large general service class, and $0.00760 per kwh for all other customer classes. The 2010 MNRRA was established with an expected recovery of $16.2 million over the period September 1, 2010 to August 31, 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 the MNRRA regulatory asset, which will be recovered under the MNRRA rider over a period ending in September 2014. Effective October 1, 2011 the MNRRA rider was set at $0.00087 per kwh plus $0.092 per kW for the large general service class, and $0.00103 per kwh for all other customer classes. OTP has a regulatory asset of $2.2 million for revenues that are eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of March 31, 2012.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or otherwise deemed eligible by the MPUC. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs currently being recovered through OTP's Minnesota 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 has a regulatory asset of $0.3 million for revenues that are eligible for recovery through the Minnesota TCR rider that have not been billed to Minnesota customers as of March 31, 2012. OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. The update to OTP's Minnesota TCR rider was approved by the MPUC in an order dated March 26, 2012. Effective April 1, 2012 the Minnesota TCR rider rate is $0.391 per kW for the large general service class, $0.00019 per kwh for the controlled service class, $0.00085 per kwh for the lighting class, and $0.00126 per kwh for all other customer classes.

In this TCR rider update the MNPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO tariff. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. The MNPUC considered two possible approaches to recovery of OTP's transmission investments in excess of amounts allocated back to its retail load-serving obligations: (1) a split method in which OTP's Minnesota retail customers would be responsible only for the investment allocated back to OTP through the MISO tariff, or (2) an all-in method in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO tariff. The MNPUC approved using the all-in method on March 26, 2012.

Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal. On July 1, 2010 OTP filed its plan for 2011-2013. The Minnesota Department of Commerce (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

A written order was issued by the MPUC on January 11, 2012 approving the recovery of $3.5 million for the 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for $2.6 million and an update to the CCRA with a proposed July 1, 2012 effective date.

OTP has a regulatory asset of $6.7 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 March 31, 2012. OTP recognized MN conservation costs and incentive totaling $0.8 million in the first quarter of 2012 compared with $1.8 million in the first quarter of 2011.

North Dakota

Renewable Resource Cost Recovery Rider—The 2010 North Dakota Renewable Resource Adjustment (NDRRA) of $0.00473 per kwh plus $0.212 per kW for the large general service class, and $0.0051 per kwh for all other customer classes, was in place for the period of September 1, 2010 through March 31, 2012 with an expected recovery of $15.8 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with a proposed April 1, 2012 effective date. The North Dakota Public Service Commission (NDPSC) approved OTP's request for an updated NDRRA on March 21, 2012. Effective April 1, 2012 the NDRRA will be $0.00410 per kwh plus $0.705 per kW for the large general service class and $0.00556 per kwh for all other customer classes. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 through March 31, 2013.

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 filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011. On April 25, 2012 the NDPSC approved the use of the split method of cost recovery for the North Dakota TCR rider. Effective May 1, 2012 the North Dakota TCR rider is $0.785 per kW for the large general service class, $0.00031 per kwh for the controlled service class, $0.00113 per kwh for the lighting class, and $0.00205 per kwh for all other customer classes.

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% 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 was approved by the SDPUC and implemented on December 1, 2011. OTP's TCR rider rate is reflected on South Dakota customer electric service statements at $0.00083 per kwh plus $0.072 per kW for large general service customers, $0.00020 per kwh for controlled service customers, $0.00108 per kwh for lighting customers, and $0.00180 per kwh for all other customers.

Energy Efficiency Plan—OTP's energy efficiency plan for South Dakota customers provides for recovery of program costs, carrying costs and a financial incentive through an approved rider. On June 16, 2010 OTP filed a request with the SDPUC for approval of updates to its 2010 South Dakota Energy Efficiency Plan (EEP) and approval for the continuation of the program in 2011. OTP requested increases in energy and demand savings goals and increases in related financial incentives for both 2010 and the requested 2011 program. In an order issued on July 27, 2010 the SDPUC approved OTP's request for updated energy, demand and participation goals for continuation of the program into 2011.

On April 29, 2011 OTP filed a request with the SDPUC for approval of a 2010 financial incentive of $73,415 and a surcharge adjustment of $0.00063 on South Dakota customers' bills. On May 25, 2011 OTP filed a request with the SDPUC for approval of updates to its 2012–2013 South Dakota EEP. The SDPUC approved the 2012–2013 plan with a maximum available incentive payment limited to 30% of the budget amount provided in the plan. A written order was issued on August 26, 2011 approving the 2010 financial incentive of $73,145. On April 30, 2012 OTP filed its 2011 status report with the SDPUC. This filing included a request for approval of the 2011 financial incentive of $78,900 and an update to the EEP Adjustment Rider.

Federal

Wholesale power sales and transmission rates are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Federal Power Act of 1935, as amended. The FERC is an independent agency, with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Effective January 1, 2010, the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). OTP was also authorized by the FERC to recover in its formula rate (1) 100% of prudently incurred Construction Work in Progress (CWIP) in rate base and (2) 100% prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery) specifically for three regional transmission CapX2020 projects that OTP is investing in, including the Fargo project, Bemidji project and Brookings project.

On December 16, 2010, FERC approved the cost allocation for a new classification of projects in MISO called Multi-Value Projects (MVP). MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011, FERC reaffirmed the MVP cost allocation on Rehearing. The MVP cost allocation is currently being challenged at the United States Court of Appeals, 7th Circuit.

Effective January 1, 2012, the FERC authorized OTP to recover 100% CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVP's in MISO's 2011 Transmission Expansion Plan: the Big Stone South – Brookings MVP and the Ellendale – Big Stone South MVP.

Capacity Expansion 2020 (CapX2020)

CapX2020 is a joint initiative of eleven 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. Recovery of OTP's CapX2020 transmission investments will be through the MISO tariff and Minnesota, North Dakota and South Dakota TCR Riders.

The Fargo Project—The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. OTP's share of this project is approximately $10.8 million.

The MPUC approved a route permit for the St. Cloud to Fargo portion of the Fargo Project 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. Construction on Phase 2 began in November 2011 and is expected to be completed in the fourth quarter of 2013.

A combined North Dakota Certificate of Corridor Compatibility (CCC) and route permit application was submitted to the NDPSC on October 3, 2011. The NDPSC conducted a hearing on January 30, 2012. The project expects to receive final permit approval from the NDPSC by the end of the second quarter of 2012. Once all final permits have been received from the NDPSC, project agreements for Phase 3, which consists of the line section between Alexandria, Minnesota and Fargo, North Dakota, would be executed with the project partners.

The Brookings Project—The MPUC approved the final line segment route permit for the Brookings Project on February 3, 2011. OTP executed project agreements with co-owners on January 13, 2012. The NDPSC approved the request for an Advanced Determination of Prudence (ADP) on November 10, 2011. The South Dakota route permit was approved by the SDPUC in June 2011. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project will be placed in service in segments with the earliest segment being placed in service in the summer of 2013 and the last segment placed in service during the first quarter of 2015.

The Bemidji Project—OTP serves as the lead utility for the Bemidji Project, which has an expected in-service date in the fourth quarter of 2012. The MPUC approved the CON for this project on July 9, 2009. A route permit application was approved by the MPUC on October 28, 2010. The joint state and federal Environmental Impact Statement 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 a judgment 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 with the MPUC, and from taking any other actions to interfere with the routing or construction of the project. The preliminary injunction remains in place prohibiting the LLBO from interfering with project construction.

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. On March 29, 2012 the EPA took final action to approve South Dakota's Regional Haze State Implementation Plan (SIP), finding that South Dakota's SIP submittal met all applicable regional haze regulations. The EPA's final approval of the SIP was published in the Federal Register on April 26, 2012, and the effective date is May 29, 2012.

On January 14, 2011 OTP filed a petition asking the MPUC for 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 December 20, 2011 the MPUC decided that OTP met the requirements of the ADP statute and granted OTP's petition for ADP for the Big Stone Plant Air Quality Control System (AQCS). The MPUC written order was issued on January 23, 2012. OTP expects to file a multi-year rate plan in Minnesota that would allow recovery of the costs for the Big Stone Plant AQCS.

OTP filed an application for an ADP with the NDPSC on May 20, 2011. The NDPSC hired a consulting firm to evaluate the ADP request. Evidentiary hearings were held on November 29, 2011. There was no opposition in this proceeding. OTP and NDPSC advocacy staff entered into a settlement agreement that was filed with the NDPSC on January 9, 2012. The NDPSC has held multiple working sessions on the matter and a final decision is expected in the second quarter of 2012.

On March 30, 2012 OTP requested approval from the SDPUC for an Environmental Cost Recovery Rider to recover costs associated with the Big Stone Plant AQCS, with a proposed effective date of October 1, 2012. This rider is designed to recover the revenue requirements plus carrying charges of the Big Stone ACQS project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case. For the initial period of October 1, 2012 through September 30, 2013, OTP is requesting revenue requirement recovery on expenditures incurred for the Big Stone Plant AQCS.

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:

	March 31, 2012			Remaining
(in thousands)	Current	Long-Term	Total	Recovery/ Refund Period
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 7,047	$ 93,570	$ 100,617	see notes
Deferred Marked-to-Market Losses	7,268	12,770	20,038	41 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	3,503	3,166	6,669	15 months
Accumulated ARO Accretion/Depreciation Adjustment	--	3,777	3,777	asset lives
Big Stone II Unrecovered Project Costs – Minnesota	503	2,015	2,518	54 months
Debt Reacquisition Premiums	277	2,180	2,457	246 months
Minnesota Renewable Resource Rider Accrued Revenues	1,148	1,057	2,205	30 months
Deferred Income Taxes	--	2,200	2,200	asset lives
Big Stone II Unrecovered Project Costs – North Dakota	1,364	447	1,811	16 months
North Dakota Renewable Resource Rider Accrued Revenues	1,045	301	1,346	24 months
North Dakota Transmission Rider Accrued Revenues	1,201	--	1,201	12 months
Big Stone II Unrecovered Project Costs – South Dakota	100	786	886	106 months
General Rate Case Recoverable Expenses	679	143	822	22 months
Minnesota Transmission Rider Accrued Revenue	329	--	329	12 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	249	--	249	8 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	189	--	189	9 months
Deferred Holding Company Formation Costs	55	69	124	27 months
Other Regulatory Assets	23	--	23	12 months
Total Regulatory Assets	$ 24,980	$ 122,481	$ 147,461	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 65,717	$ 65,717	asset lives
Deferred Income Taxes	--	3,170	3,170	asset lives
Deferred Marked-to-Market Gains	137	--	137	11 months
	5	116	121	261 months

Deferred Gain on Sale of Utility Property – Minnesota Portion							
South Dakota – Nonasset-Based Margin Sharing Excess		56		--		56	9 months
Total Regulatory Liabilities	$	198	$	69,003	$	69,201	
Net Regulatory Asset Position	$	24,782	$	53,478	$	78,260	

(in thousands)		December 31, 2011		Remaining Recovery/
	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 6,304	$ 96,074	$ 102,378	see notes
Deferred Marked-to-Market Losses	5,208	10,749	15,957	44 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	5,234	2,208	7,442	18 months
Accrued Cost-of-Energy Revenue	4,043	--	4,043	12 months
Accumulated ARO Accretion/Depreciation Adjustment	--	3,662	3,662	asset lives
Minnesota Renewable Resource Rider Accrued Revenues	1,461	1,306	2,767	33 months
Big Stone II Unrecovered Project Costs – Minnesota	495	2,144	2,639	57 months
Debt Reacquisition Premiums	280	2,246	2,526	249 months
Deferred Income Taxes	--	2,382	2,382	asset lives
Big Stone II Unrecovered Project Costs – North Dakota	1,340	862	2,202	19 months
North Dakota Renewable Resource Rider Accrued Revenues	785	1,325	2,110	24 months
General Rate Case Recoverable Expenses	721	285	1,006	25 months
Big Stone II Unrecovered Project Costs – South Dakota	100	811	911	109 months
North Dakota Transmission Rider Accrued Revenue	518	--	518	12 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	343	--	343	11 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	252	--	252	12 months
Deferred Holding Company Formation Costs	55	83	138	30 months
South Dakota – Asset-Based Margin Sharing Shortfall	138	--	138	2 months
South Dakota Transmission Rider Accrued Revenues	114	--	114	12 months
Total Regulatory Assets	$ 27,391	$ 124,137	$ 151,528	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 65,610	$ 65,610	asset lives
Deferred Income Taxes	--	3,379	3,379	asset lives
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	117	123	264 months
Deferred Marked-to-Market Gains	96	--	96	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	54	--	54	12 months
Minnesota Transmission Rider Accrued Refund	28	--	28	see notes

Total Regulatory Liabilities	$	184	$	69,106	$	69,290
Net Regulatory Asset Position	$	27,207	$	55,031	$	82,238

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 March 31, 2012 are related to forward purchases of energy scheduled for delivery through August 2015.

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

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 – 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 246 months.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through March 31, 2012 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of March 31, 2012.

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.

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.

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 March 31, 2012.

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facility and net operating costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of March 31, 2012.

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. 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.

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

Minnesota Transmission Rider Accrued Revenue relates to revenues earned on qualifying transmission system facilities and net operating costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of March 31, 2012.

MISO Schedule 26 Transmission Cost Recovery Rider True-up relates to the Minnesota jurisdictional portion of MISO Schedule 26 for regional transmission cost recovery that was included in the calculation of the Minnesota Transmission Rider and subsequently adjusted to reflect actual billing amounts in the schedule.

South Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facility and net operating costs incurred to serve South Dakota customers that have not been billed to South Dakota customers as of March 31, 2012.

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

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, Fair Value Measurement.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of March 31, 2012 and December 31, 2011, and the change in the Company's consolidated balance sheet position from December 31, 2011 to March 31, 2012 and December 31, 2010 to March 31, 2011:

(in thousands)	March 31, 2012	December 31, 2011
Other Current Asset – Derivative Asset	$ 5,391	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	7,268	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	12,770	10,749
Total Assets	25,429	19,760
Derivative Liability	(24,682)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(137)	(96)
Total Liabilities	(24,819)	(18,866)
Fair Value Adjustments Included in Earnings	$ 610	$ 894

(in thousands)	Year-to-Date March 31, 2012	Year-to-Date March 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$894	$763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(478)	(96)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(32)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	383	635
Changes in Fair Value of Contracts Entered into in Current Period	227	(3)
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$610	$632

The recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on March 31, 2012 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2nd Qtr 2012	3rd Qtr 2012	4th Qtr 2012	1st Qtr 2013	Total
Net Gain	$ 399	$ 81	$ 95	$ 35	$ 610

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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 March 31,	
(in thousands)	2012	2011
Net Gains (Losses) on Forward Electric Energy Contracts	$ 194	$ (8)

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. The Company has 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 March 31, 2012 and December 31, 2011:

	March 31, 2012		December 31, 2011	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$1,793	8	$1,677	10
Net Credit Risk to Single Largest Counterparty	$1,053		$737	

OTP had a net credit risk exposure to eight counterparties with investment grade credit ratings. OTP had no exposure at March 31, 2012 or December 31, 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 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 March 31, 2012 and December 31, 2011:

Current Liability – Marked-to-Market Loss (in thousands)	March 31, 2012	December 31, 2011
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 4,502	$ 3,423
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	20,180	15,347
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$ 24,682	$ 18,770
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	$ 20,180	$ 15,347
Offsetting Gains with Counterparties under Master Netting Agreements	(3,235)	(3,471)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 16,945	$ 11,876

6. Common Shares and Earnings Per Share

Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2011 through March 31, 2012:

Common Shares Outstanding, December 31, 2011	36,101,695
Issuances:	
Vesting of Restricted Stock Units	7,925
Retirements:	
Forfeiture of Unvested Restricted Stock	(1,825)
Common Shares Outstanding, March 31, 2012	36,107,795

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 price for the quarters ended March 31, 2012 and 2011:

Quarter Ended March 31,	Options Outstanding	Range of Exercise Prices
2012	156,397	$24.93 – $31.34
2011	383,460	$24.93 – $31.34

7. Share-Based Payments

The Company has five share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2012. As of March 31, 2012 the remaining unrecognized compensation expense related to stock-based compensation was approximately $1.7 million (before income taxes) which will be amortized over a weighted-average period of 2.4 years.

Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three months ended March 31, 2012 and 2011 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2012	2011
Employee Stock Purchase Plan (15% discount)	$39	$62
Restricted Stock Granted to Directors	136	192

Restricted Stock Granted to Employees	58	115
Restricted Stock Units Granted to Employees	54	83
Stock Performance Awards Granted to Executive Officers	--	--
Totals	$287	$452

8. Retained Earnings Restriction

The Company's Restated Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company’s cumulative preferred shares. Under these provisions none of the Company’s retained earnings were restricted at March 31, 2012.

9. Commitments and Contingencies

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts
OTP has commitments for capacity and energy requirements under agreements extending through 2032. OTP did not enter into any agreements for the purchase of additional capacity or energy to meet future capacity and energy requirements in the first quarter of 2012. OTP’s current coal purchase agreements under contracts expire in 2012 and 2016. OTP did not commit to any additional coal purchases in the first quarter of 2012.

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 March 31, 2012 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 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 $7.0 million. Additionally, the Company may become subject to significant claims of which its management is unaware, or the claims of which its management is aware may result in the Company incurring a significantly greater liability than it anticipates.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of March 31, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on March 31, 2012	Restricted due to Outstanding Letters of Credit	Available on March 31, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$200,000	$1,095	$850	$198,055	$198,776
OTP Credit Agreement	170,000	2,193	4,550	163,257	165,950
Total	$370,000	$3,288	$5,400	$361,312	$364,726

On March 31, 2012 the Company’s construction subsidiary, Foley Company, had $23,000 outstanding in short-term borrowings related to construction activity.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of March 31, 2012 and December 31, 2011:

March 31, 2012 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$2,193	$23	$1,095	$ 3,311
Long-Term Debt:				
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 4.63%, due December 1, 2021	140,000			140,000
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 3.95% at March 31, 2012		$2,833	1,854	4,687
Total	$320,195	$2,833	$151,854	$ 474,882
Less: Current Maturities	--	2,833	167	3,000
Unamortized Debt Discount	--	--	4	4
Total Long-Term Debt	$320,195	$--	$151,683	$ 471,878
Total Short-Term and Long-Term Debt (with current maturities)	$322,388	$2,856	$152,945	$ 478,189

December 31, 2011 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$--	$ --	$ --
Long-Term Debt:				
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 4.63%, due December 1, 2021	140,000			140,000
	30,000			30,000

Senior Unsecured Notes 6.15%, Series B, due August 20, 2022				
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 3.95% at December 31, 2011		$2,868	1,889	4,757
Total	$320,195	$2,868	$ 151,889	$ 474,952
Less: Current Maturities	--	2,868	165	3,033
Unamortized Debt Discount	--	--	4	4
Total Long-Term Debt	$320,195	$--	$ 151,720	$ 471,915
Total Short-Term and Long-Term Debt (with current maturities)	$320,195	$2,868	$ 151,885	$ 474,948

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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:

(in thousands)	Three Months Ended March 31, 2012	2011
Service Cost—Benefit Earned During the Period	$1,294	$1,175
Interest Cost on Projected Benefit Obligation	3,108	3,175
Expected Return on Assets	(3,608)	(3,537)
Amortization of Prior-Service Cost	102	100
Amortization of Net Actuarial Loss	1,231	650
Net Periodic Pension Cost	$2,127	$1,563

Cash flows—The Company had a minimum funding requirement of $3,015,000 as of December 31, 2011, and made a discretionary plan contribution of $10,000,000 in January 2012. The Company is not required to make any additional contributions in 2012. The Company did not make a contribution to its pension plan in the three months ended March 31, 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:

(in thousands)	Three Months Ended March 31, 2012	2011
Service Cost—Benefit Earned During the Period	$11	$20
Interest Cost on Projected Benefit Obligation	370	408
Amortization of Prior-Service Cost	18	19
Amortization of Net Actuarial Loss	82	61
Net Periodic Pension Cost	$481	$508

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:

(in thousands)	Three Months Ended March 31, 2012	2011
Service Cost—Benefit Earned During the Period	$461	$425
Interest Cost on Projected Benefit Obligation	881	850
Amortization of Transition Obligation	187	187
Amortization of Prior-Service Cost	52	50
Amortization of Net Actuarial Loss	391	213
Effect of Medicare Part D Expected Subsidy	(487)	(525)
Net Periodic Postretirement Benefit Cost	$1,485	$1,200

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 Cash Equivalents—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 market indications of rates available to the Company for the issuance of debt. The Company’s long-term debt subject to variable interest rates approximates fair value.

	March 31, 2012		December 31, 2011	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$--	$--	$14,652	$14,652
Long-Term Debt	$(471,878)	$(529,957)	$(471,915)	$(525,041)

15. Income Tax Expense – Continuing Operations

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company’s consolidated statements of income for the three month periods ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
(in thousands)	2012	2011
Income Before Income Taxes – Continuing Operations	$9,788	$6,451
Add Back Canadian Losses not Subject to Income Tax Benefits	451	3,497
Income Before Income Taxes – Continuing Operations, Subject to Taxes	10,239	9,948
Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%)	3,993	3,879
Increases (Decreases) in Tax from:		
Federal Production Tax Credits	(1,987)	(1,976)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	(676)	--
Corporate Owned Life Insurance	(372)	(88)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(222)	(290)
Medicare Part D Subsidy	(197)	(192)
Employee Stock Ownership Plan Dividend Deduction	(190)	(194)
Canadian Revenue Authority Audit Settlement	--	156
Other Items - Net	(52)	(57)
Income Tax Expense – Continuing Operations	$297	$1,238
Effective Income Tax Rate – Continuing Operations	3.0%	19.2%

17. Discontinued Operations

On May 6, 2011, the Company completed the sale of IPH for approximately $87.0 million in cash, including $3.0 million deposited in an escrow account. In the second half of 2011, the IPH sales proceeds were reduced by $1.2 million related to a purchase price adjustment. On December 29, 2011 the Company completed the sale of Wylie, its trucking business, for approximately $25.0 million in cash. On January 18, 2012 the Company sold the assets of Aviva for $0.3 million in cash. On February 29, 2012 the Company sold DMS for $28.3 million in cash. Following are summary presentations of the results of discontinued operations for three month periods ended March 31, 2012 and 2011, along with the major components of assets and liabilities of discontinued operations as of March 31, 2012 and December 31, 2011:

	For the Three Months Ended March 31, 2012				
(in thousands)	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$--	$1	$16,362	$ (11)	$16,352
Operating Expenses	159	13	14,741	(11)	14,902
Operating (Loss) Income	(159)	(12)	1,621	--	1,450
Interest Charges	--	--	279	(132)	147
Other Income	--	--	122	--	122
Income Tax (Benefit) Expense	(64)	(5)	600	53	584
Net (Loss) Income from Operations	(95)	(7)	864	79	841
Loss on Disposition Before Taxes	(44)	--	(3,179)	--	(3,223)
Income Tax Benefit on Disposition	(18)	--	(116)	--	(134)
Net Loss on Disposition	(26)	--	(3,063)	--	(3,089)
Net Income (Loss)	$(121)	$(7)	$(2,199)	$ 79	$(2,248)

	For the Three Months Ended March 31, 2011					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$20,645	$14,609	$952	$22,495	$ (523)	$58,178
Operating Expenses	17,617	17,535	1,503	21,412	(523)	57,544
Operating Income (Loss)	3,028	(2,926)	(551)	1,083	--	634
Interest Charges	8	213	96	400	(697)	20
Other (Deductions) Income	(146)	11	(4)	298	(2)	157
Income Tax Expense (Benefit)	1,112	(1,249)	(260)	409	276	288
Net Income (Loss)	$1,762	$(1,879)	$(391)	$572	$ 419	$483

	March 31, 2012				
(in thousands)	IPH	Wylie	Aviva	DMS	Total
Current Assets	$--	$--	$529	$--	$529
Net Plant	--	--	--	--	--
Assets of Discontinued Operations	$--	$--	$529	$--	$529
Current Liabilities	$--	$--	$269	$--	$269
Deferred Income Taxes	--	--	(232)	--	(232)
Deferred Credits - Other	--	--	--	--	--
Long-Term Debt	--	--	--	--	--
Liabilities of Discontinued Operations	$--	$--	$37	$--	$37

	December 31, 2011				
(in thousands)	IPH	Wylie	Aviva	DMS	Total
Current Assets	$--	$--	$912	$28,408	$29,320
Net Plant	--	--	--	372	372
Assets of Discontinued Operations	$--	$--	$912	$28,780	$29,692
Current Liabilities	$--	$--	$399	$14,341	$14,740
Deferred Income Taxes	--	--	(232)	(1,579)	(1,811)
Deferred Credits - Other	--	--	--	119	119
Long-Term Debt	--	--	--	715	715
Liabilities of Discontinued Operations	$--	$--	$167	$13,596	$13,763

18. Subsequent Events

Stock Incentive Awards

On April 16, 2012 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	$21.32	25% per year through April 8, 2016
Restricted Stock Granted to Executive Officers	24,500	$21.32	25% per year through April 8, 2016
Stock Performance Awards Granted to Executive Officers	80,800	$21.75	December 31, 2014
Restricted Stock Units Granted to Employees	12,800	$17.14	100% on April 8, 2016

The restricted shares granted to the Company's nonemployee directors and executive officers 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 161,600 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, 2012 through December 31, 2014. The aggregate target share award is 80,800 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, 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.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three months ended March 31, 2012 and 2011, followed by a discussion of changes in our consolidated financial position during the three months ended March 31, 2012 and our business outlook for the remainder of 2012.

Comparison of the Three Months Ended March 31, 2012 and 2011

Consolidated operating revenues were $277.6 million for the three months ended March 31, 2012 compared with $249.1 million for the three months ended March 31, 2011. Operating income was $17.4 million for the three months ended March 31, 2012 compared with $15.6 million for the three months ended March 31, 2011. The Company recorded diluted earnings per share from continuing operations of $0.26 for the three months ended March 31, 2012 compared to $0.14 for the three months ended March 31, 2011 and total diluted earnings per share of $0.20 for the three months ended March 31, 2012 compared to $0.15 for the three months ended March 31, 2011.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended March 31, 2012 and 2011 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)	March 31, 2012	March 31, 2011
Operating Revenues:		
Electric	$ 65	$ 70
Nonelectric	937	720
Cost of Goods Sold	945	543
Other Nonelectric Expenses	57	247

Electric

(in thousands)	Three Months Ended March 31, 2012	2011	Change	% Change
Retail Sales Revenues	$ 81,422	$ 82,903	$ (1,481)	(1.8)
Wholesale Revenues – Company Generation	2,079	2,736	(657)	(24.0)
Net Revenue – Energy Trading Activity	412	228	184	80.7
Other Revenues	6,090	5,729	361	6.3
Total Operating Revenues	$ 90,003	$ 91,596	$ (1,593)	(1.7)
Production Fuel	15,424	19,577	(4,153)	(21.2)
Purchased Power – System Use	14,158	12,377	1,781	14.4
Other Operation and Maintenance Expenses	30,013	28,708	1,305	4.5
Asset Impairment Charge	432	--	432	--
Depreciation and Amortization	10,400	10,039	361	3.6
Property Taxes	2,617	2,409	208	8.6
Operating Income	$ 16,959	$ 18,486	$ (1,527)	(8.3)

Three Months Ended

Electric kwh Sales (in thousands)	March 31, 2012	2011	Change	% Change
Retail kilowatt-hour (kwh) Sales	1,204,605	1,306,123	(101,518)	(7.8)
Wholesale kwh Sales – Company Generation	95,391	98,257	(2,866)	(2.9)
Wholesale kwh Sales – Purchased Power Resold	6,400	63,252	(56,862)	(89.9)

The $1.5 million decrease in retail sales revenues reflects the following:

- a $4.4 million decrease in revenues, mainly due to a 7.8% reduction in retail kwh sales resulting from significantly milder weather in the first quarter of 2012 as heating degree days were down 27.8% compared with the first quarter of 2011,
- a $2.8 million decrease in revenue related to the recovery of fuel and purchased power costs, and
- a $1.0 million reduction in accrued conservation program cost recovery revenues related to the timing of the recognition of conservation costs recovered through the Minnesota Conservation Improvement Program surcharge,

offset by:

- a $3.0 million increase in revenue related to revised winter rates implemented in Minnisota in October 2011 on finalization of Otter Tail Power Company's 2010 general rate case,
- a $2.3 million revenue reduction in the first quarter of 2011 related to accruing a refund of a portion of revenues collected under interim rates during the most recent Minnesota rate case, and
- a $1.4 million increase in transmission costs recovery rider revenues as a result of increased investment in transmission assets.

Wholesale electric revenues from company-owned generation decreased $0.7 million mainly as a result of a 21.7% decrease in the average price per wholesale kwh sold. Wholesale electric prices were down as a result of decreased demand and lower utilization of higher cost generation due to the extremely mild winter of 2012.

Other electric operating revenues increased $0.4 million as a result of:

- a $2.1 million increase in transmission tariff revenues due, in part, to revenues from CapX2020 transmission project investments,

offset by:

- a reduction in revenue related to the sale of access rights through an Otter Tail Energy Services Company (OTESCO) wind farm development site in the first quarter of 2011 for $1.1 million, and
- a $0.6 million reduction in revenues from steam sales at Big Stone Plant to a nearby ethanol plant as a result of the customer generating more of its own steam from its natural gas fired boiler in response to low natural gas prices.

Fuel costs decreased $4.2 million as a result of a 23.8% decrease in kwhs generated from Otter Tail Power Company’s (OTP) steam-powered and combustion turbine generators, partially offset by a 3.4% increase in the cost of fuel per kwh generated. Generation levels decreased in response to lower demand due to mild weather and a forced outage at Big Stone Plant in February 2012 to repair boiler steam tube leaks. The cost of purchased power for retail sales increased $1.8 million as a result of a 24.5% increase in kwhs purchased, partially offset by an 8.1% decrease in the cost per kwh purchased. The increase in kwhs purchased was mainly a due to reduced availability of Big Stone Plant in the first quarter of 2012.

Electric operating and maintenance expenses increased $1.3 million due to the following:

- a $0.9 million increase in employee benefit expenses mainly due to increases in pension and retirement health benefit costs resulting from a reduction in the discount rate related to projected benefit obligations,
- a $0.8 million increase in MISO Schedule 26 transmission service charges,
- a $0.4 million increase in vegetation management expenses,
- bad debt expense was $0.4 million less in the first quarter of 2011 as a result of OTP adjusting its allowance for uncollectible accounts, and
- a $0.2 million increase in amortized expenses related to the recovery of OTP's Minnesota portion of Big Stone II plant abandonment costs, which began in the fourth quarter of 2011,

offset by:

- a $1.0 million reduction in incurred conservation program costs, commensurate with a reduction in accrued revenues related to the future recovery of those costs, and a $0.4 million decrease in expenses related to recording a discount on the Minnesota portion of Big Stone II recoverable costs in the first quarter of 2011 based on a settlement agreement with the Minnesota Public Utilities Commission granting recovery of a portion of the abandoned project's costs.

OTESCO recorded an additional $0.4 million asset impairment charge related to its wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota as a potential sale of the rights did not occur as expected in the first quarter of 2012. The $0.4 million increase in Electric segment depreciation expense is related to 2011 property additions. The $0.2 million increase in property taxes is mainly due to higher taxes on electric distribution property.

Wind Energy

(in thousands)	Three Months Ended March 31, 2012	2011	Change	% Change
Revenues	$ 52,102	$ 46,988	$ 5,114	10.9
Cost of Goods Sold	47,584	47,884	(300)	(0.6)
Operating Expenses	1,578	2,478	(900)	(36.3)
Depreciation and Amortization	2,082	2,512	(430)	(17.1)
Operating Income (Loss)	$ 858	$ (5,886)	$ 6,744	114.6

Revenues at the U.S. plants of DMI Industries, Inc. (DMI) increased $16.3 million between the quarters due to a 22.3% increase in towers produced. Revenues and cost of goods sold at DMI’s Canadian plant were down $11.2 million and $13.2 million, respectively, as a result of the idling of plant in the fourth quarter of 2011 due to a reduction in tower orders. Cost of goods sold at DMI’s U.S. plants increased $12.9 million as a result of increased production. However, operating margins at the U.S. plants improved in the first quarter of 2012 compared with the first quarter of 2011 as a result of productivity improvements, cost controls and the implementation of quality control measures that have eliminated the need for outsourced quality assurance staffing. DMI’s operating expenses decreased $0.5 million at its idled Canadian plant. In DMI’s remaining areas of operations, operating expenses decreased $0.4 million, mainly as a result of lower salary and benefit expenses due to staff reductions. Depreciation expense decreased as a result of extending the depreciable lives of certain equipment at DMI’s U.S. plants and as a result of the impairment of assets in Canada in 2011.

Manufacturing

(in thousands)	Three Months Ended March 31, 2012	2011	Change	% Change
Operating Revenues	$ 65,994	$ 55,361	$ 10,633	19.2
Cost of Goods Sold	50,711	41,989	8,722	20.8
Operating Expenses	7,086	4,548	2,538	55.8
Depreciation and Amortization	3,196	3,170	26	0.8
Operating Income	$ 5,001	$ 5,654	$ (653)	(11.5)

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 $11.9 million as a result of higher sales volume due to improved customer demand.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased by $0.6 million due to increased sales of industrial products.

Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment business, decreased $1.8 million, reflecting a $2.5 million decrease in commercial sales, partially offset by a $0.7 million increase in residential sales.

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

Cost of goods sold at BTD increased $9.2 million as a result of increased sales volume.

Cost of goods sold at T.O. Plastics increased $0.4 million as a result of costs associated with the increase in sales of industrial products, offset by a $0.3 million decrease in costs related to improved productivity and efficiencies.

Cost of goods sold at ShoreMaster decreased $0.6 million. A decrease in costs related to the reduction in sales of commercial products was partially offset by $0.5 million in costs incurred to relocate ShoreMaster's commercial production operations in Camdenton, Missouri to its Fergus Falls, Minnesota and St. Augustine, Florida locations.

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

Operating expenses at BTD increased $1.3 million due to increased salary and benefit expenses related to workforce expansion, and increases in expenditures for contracted services and travel.

Operating expenses at T.O. Plastics decreased $0.1 million between the quarters.

Operating expenses at ShoreMaster increased $1.3 million, reflecting a $0.4 million increase in expenses for outside professional services, a first quarter 2011 expense reduction of $0.7 million from the collection of a receivable written off as uncollectible prior to 2011, and a $0.2 million gain on a first quarter 2011 asset sale.

Construction

(in thousands)	Three Months Ended March 31, 2012	2011	Change	% Change
Operating Revenues	$ 35,617	$ 37,515	$ (1,898)	(5.1)
Cost of Goods Sold	38,693	34,289	4,404	12.8
Operating Expenses	3,280	3,106	174	5.6
Depreciation and Amortization	434	445	(11)	(2.5)
Operating Loss	$ (6,790)	$ (325)	$ (6,465)	--

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

Revenues at Foley Company, a mechanical and prime contractor on industrial projects, decreased $7.1 million, mainly due to the effect of cost overruns on estimated revenues recognized under percentage-of-completion accounting.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $5.2 million between the quarters as a result an increase in electrical transmission, distribution and substation work facilitated by the mild weather in the first quarter of 2012.

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

Cost of goods sold at Foley Company decreased $0.3 million between the quarters.

Cost of goods sold at Aevenia increased $4.7 million between the quarters as a result of the increase in electrical transmission, distribution and substation work performed in the first quarter of 2012.

The increase in operating expenses in our Construction segment reflects increases in labor, benefit and outside service expenses at Foley.

Plastics

(in thousands)	Three Months Ended March 31, 2012	2011	Change	% Change
Operating Revenues	$ 34,875	$ 18,478	$ 16,397	88.7
Cost of Goods Sold	26,947	16,720	10,227	61.2
Operating Expenses	1,363	1,221	142	11.6
Depreciation and Amortization	813	803	10	1.2
Operating Income (Loss)	$ 5,752	$ (266)	$ 6,018	--

Operating revenues for the Plastics segment increased as result of a 58.0% increase in pounds of polyvinyl chloride (PVC) pipe sold combined with a 19.5% increase in the price per pound of pipe sold. The increase in costs of goods sold was related to the increase in pounds of pipe sold, however, the cost per pound of PVC pipe sold only increased by 2.0% between the quarters. The increase in operating expenses in the Plastics segment is due to an increase in outside sales commissions related to the increase in sales volume.

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 March 31, 2012	2011	Change	% Change
Operating Expenses	$ 4,241	$ 1,970	$ 2,271	115.3
Depreciation and Amortization	128	137	(9)	(6.6)

The increase in corporate operating expenses mainly is due to higher employee benefit costs and increased costs for insurance programs and outside services.

Interest Charges

Interest charges decreased $0.9 million in the first three months of 2012 compared with the first three months of 2011, mainly as a result of a $96.5 million decrease in the average balance of short-term debt outstanding between the quarters.

Other Income

The increase in other income of $0.6 million in the first three months of 2012 compared with the first three months of 2011 includes a $0.2 million decrease in foreign currency transaction losses in the Canadian operations of DMI, an increase of $0.2 million in allowance for equity funds used during construction and other miscellaneous revenues at OTP and a $0.2 million increase in the cash surrender value of corporate-owned life insurance policies.

Income Taxes – Continuing Operations

Income taxes - continuing operations decreased $0.9 million in the first quarter of 2012 compared with the first quarter of 2011.

The following table provides a reconciliation of income tax expense calculated at the Company's net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the three month periods ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
(in thousands)	2012	2011
Income Before Income Taxes – Continuing Operations	$9,788	$6,451
Add Back Canadian Losses not Subject to Income Tax Benefits	451	3,497
Income Before Income Taxes – Continuing Operations, Subject to Taxes	10,239	9,948
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	3,993	3,879
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,987)	(1,976)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	(676)	--
Corporate Owned Life Insurance	(372)	(88)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(222)	(290)
Medicare Part D Subsidy	(197)	(192)
Employee Stock Ownership Plan Dividend Deduction	(190)	(194)
Canadian Revenue Authority Audit Settlement	--	156
Other Items - Net	(52)	(57)
Income Tax Expense – Continuing Operations	$297	$1,238
Effective Income Tax Rate – Continuing Operations	3.0 %	19.2 %

Due to cumulative losses in the Canadian operations of DMI, we have no tax liability from taxable income in Canada to offset with income tax benefits on losses, therefore, we record no tax benefit related to the losses of our Canadian operations. Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Discontinued Operations

In 2011, we sold Idaho Pacific Holdings, Inc. (IPH), our food ingredient processing company and E.W. Wylie Corporation (Wylie), our trucking business. On January 18, 2012 ShoreMaster completed the sale of the assets of its wholly owned subsidiary, Aviva Sports, Inc. (Aviva), and on February 29, 2012 we completed the sale of DMS Health Technologies Inc. (DMS), our health services business. The financial position, results of operations, and cash flows of IPH, Wylie, Aviva and DMS are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the three month periods ended March 31, 2012 and 2011:

	For the Three Months Ended March 31, 2012				
(in thousands)	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total

Operating Revenues	$--	$1	$16,362	$ (11)	$16,352
Operating Expenses	159	13	14,741	(11)	14,902
Operating (Loss) Income	(159)	(12)	1,621	--	1,450
Interest Charges	--	--	279	(132)	147
Other Income	--	--	122	--	122
Income Tax (Benefit) Expense	(64)	(5)	600	53	584
Net (Loss) Income from Operations	(95)	(7)	864	79	841
Loss on Disposition Before Taxes	(44)	--	(3,179)	--	(3,223)
Income Tax Benefit on Disposition	(18)	--	(116)	--	(134)
Net Loss on Disposition	(26)	--	(3,063)	--	(3,089)
Net Income (Loss)	$(121)	$(7)	$(2,199)	$ 79	$(2,248)

	For the Three Months Ended March 31, 2011					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$20,645	$14,609	$952	$22,495	$ (523)	$58,178
Operating Expenses	17,617	17,535	1,503	21,412	(523)	57,544
Operating Income (Loss)	3,028	(2,926)	(551)	1,083	--	634
Interest Charges	8	213	96	400	(697)	20
Other (Deductions) Income	(146)	11	(4)	298	(2)	157
Income Tax Expense (Benefit)	1,112	(1,249)	(260)	409	276	288
Net Income (Loss)	$1,762	$(1,879)	$(391)	$572	$ 419	$483

FINANCIAL POSITION

The following table presents the status of our lines of credit as of March 31, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on March 31, 2012	Restricted due to Outstanding Letters of Credit	Available on March 31, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$200,000	$1,095	$ 850	$198,055	$198,776
OTP Credit Agreement	170,000	2,193	4,550	163,257	165,950
Total	$370,000	$3,288	$ 5,400	$361,312	$364,726

We believe we have the necessary liquidity to effectively conduct business operations for an extended period. 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. We expect to file a new shelf registration statement prior to the expiration of our existing shelf registration in May 2012. 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. We expect to renew this program following the filing of our new shelf registration statement. Equity or debt financing will be required in the period 2012 through 2016 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. 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 common stock dividend payments have exceeded our net (losses) income in each of the last four 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 was a party to a $40 million receivables sales agreement whereby designated customer accounts receivable were sold to General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $21.0 million were sold in the first quarter of 2012. Discounts, fees and commissions charged to operating expense for the three months ended March 31, 2012 and 2011 were $197,000 and $118,000, respectively. The balance of receivables sold that was outstanding to the buyer as of March 31, 2012 was $35.8 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows. This agreement was terminated effective April 26, 2012. DMI has negotiated payment terms with the customer whose receivables were being sold and has agreed to receive accelerated payment of receivables due from the customer in exchange for a negotiated discount for early payment.

Cash provided by operating activities from continuing operations was $6.4 million for the three months ended March 31, 2012 compared with $3.1 million for the three months ended March 31, 2011. The $3.3 million increase in cash provided by operating activities from continuing operations is mainly due to a $9.4 million reduction in cash used for working capital in combination with a $4.3 million increase in net income from continuing operations between the quarters, offset by a $10.0 million contribution to our funded pension plan in January 2012. The $9.4 million increase in cash used for working capital items between the quarters mainly reflects a reduction in cash used for receivables of $10.3 million. Receivables at DMI increased $3.2 million in the first quarter of 2012 compared with an increase of $25.4 million in the first quarter of 2011, reflecting a high volume of billing for completed towers in the first quarter of 2011. Receivables at our plastic pipe companies increased $10.1 million in the first quarter of 2012 compared with an increase of $2.2 million in the first quarter of 2011 as a result of an 88.7% increase in revenues between the quarters related to greater sales volume and higher prices. Receivables at OTP increased $0.8 million in the first quarter of 2012 compared with a decrease of $3.7 million in the first quarter of 2011, mainly reflecting a reduction in receivables from the joint owners of Big Stone Plant and Coyote Station in the first quarter of 2011.

Net cash used in investing activities of continuing operations was $35.8 million for the three months ended March 31, 2012 compared to $20.9 million for the three months ended March 31, 2011. An increase in cash used for capital expenditures at the electric utility of $20.8 million, mainly related to expenditures for CapX2020 transmission line construction projects, was partially offset by decreases in cash used for capital expenditures at all of our nonelectric operating companies totaling $5.1 million. Net proceeds from the sale of discontinued operations of $24.4 million in the first quarter of 2012, which were used to pay down short-term borrowings and for other corporate purposes, reflect proceeds, net of selling costs, of $24.1 million from the sale of DMS and $0.3 million from the sale of Aviva’s assets. Net cash used in investing activities of discontinued operations of $11.7 million in the first quarter of 2012 reflects cash used by DMS to purchase assets held under operating leases.

Net cash provided by financing activities from continuing operations decreased $16.0 million in the three months ended March 31, 2012 compared with the three months ended March 31, 2011 mainly due to a $15.2 million net decrease in short-term borrowings and checks issued in excess of cash between the quarters. We also issued $1.5 million in long-term debt in the first quarter of 2011 and paid $0.7 million in short-term and long-term debt issuance expenses.

Under its amended and restated credit agreement (the OTP Credit Agreement) OTP has available a $170 million line of credit with an accordion feature whereby the line can 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 this line of credit bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. 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 contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 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 the borrower's credit ratings. The OTP Credit Agreement expires on March 3, 2016.

Under our second amended and restated credit agreement (the Credit Agreement), which is an unsecured revolving credit facility, we have available a $200 million credit facility that we can draw on to support our nonelectric operations. Borrowings under the Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on our senior unsecured credit ratings. The Credit Agreement expires on May 4, 2013. The Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation, (Varistar) 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 Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Credit Agreement are guaranteed by certain of our material subsidiaries. Outstanding letters of credit issued by us under the Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Credit Agreement.

On December 1, 2011 OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a note purchase agreement dated July 29, 2011 (2011 Note Purchase Agreement) between OTP and the purchasers named therein. OTP used a portion of the proceeds of the 2021 Notes to retire $90 million aggregate principal amount of its 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 were used to repay short-term debt of OTP which was issued to fund capital expenditures, to pay fees and expenses related to the debt issuance and to fund a $10 million contribution to the Company’s pension plan in January 2012.

On December 4, 2009 we issued $100 million of our 9.000% notes due 2016 under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by a first supplemental indenture dated as of July 1, 2009, between us and U.S. Bank National Association (formerly First Trust National Association), as trustee. The notes are senior unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016.

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 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 2007 Note Purchase Agreement, the Cascade Note Purchase Agreement and the 2011 Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor’s ability and the ability of the obligor’s subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

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, 2011.

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. On December 12, 2011 we entered into Amendment No. 5 to the Cascade Note Purchase Agreement which permits us to exclude gains or losses from the sales of subsidiaries.

Financial Covenants
As of March 31, 2012 we were in compliance with the financial statement covenants that existed in our 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 debt agreements are subject to certain financial covenants. Specifically:

Under the 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 March 31, 2012 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 1.80 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 March 31, 2012 our Interest Charges Coverage Ratio calculated under the requirements of the Cascade Note Purchase Agreement was 1.71 to 1.00.

Under the OTP Credit 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 OTP Credit Agreement. As of March 31, 2012 OTP’s Interest and Dividend Coverage Ratio calculated under the requirements of the OTP Credit Agreement was 3.34 to 1.00.

Under the 2007 Note Purchase Agreement, the 2011 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 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 2007 Note Purchase Agreement and 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 March 31, 2012 OTP’s Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.34 to 1.00.

As of March 31, 2012 our interest-bearing debt to total capitalization was 0.45 to 1.00 on a fully consolidated basis and 0.50 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $12.3 million, but our line of credit borrowing limits are only restricted by $5.4 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.

2012 BUSINESS OUTLOOK

Based on year-to-date segment performance, we are updating our 2012 expectations for diluted earnings per share from continuing operations to a range of $1.05 to $1.40 from our previously announced range of $1.00 to $1.40. This guidance considers the cyclical nature of some of our businesses and reflects challenges presented by current economic conditions, as well as our plans and strategies for improving future operating results. Our current consolidated capital expenditures expectation for 2012 is in the range of $125 million to $135 million. This compares with $74 million of capital expenditures in 2011. We plan to invest in generation and transmission projects for the Electric segment that have the potential to positively impact our earnings and returns on capital. Future Electric segment investments include the construction of a new air quality control system at Big Stone Plant to meet requirements of the Clean Air Act and regional haze regulations, investment in two MISO-determined ‘multi-value’ transmission projects that will serve the MISO region, and continuing investment, with other utilities, in three CapX2020 transmission projects already underway.

Segment components of our updated 2012 earnings per share guidance range are as follows:

Original 2012 Earnings Per Share Guidance Range	Low	High	Updated 2012 Earnings Per Share Guidance Range	Low	High
Electric	$ 1.05	$ 1.10	Electric	$ 1.00	$ 1.05
Wind Energy	$ (0.15)	$ 0.00	Wind Energy	$ (0.10)	$ 0.00
Manufacturing	$ 0.30	$ 0.35	Manufacturing	$ 0.36	$ 0.41
Construction	$ 0.02	$ 0.07	Construction	$ (0.13)	$ (0.08)
Plastics	$ 0.06	$ 0.11	Plastics	$ 0.18	$ 0.23
Corporate	$ (0.28)	$ (0.23)	Corporate	$ (0.26)	$ (0.21)
Total – Continuing Operations	$ 1.00	$ 1.40	Total – Continuing Operations	$ 1.05	$ 1.40
			Earnings – Discontinued Operations	$ 0.00	$ 0.03
			Loss on Sale of Discontinued Operations	$ (0.10)	$ (0.08)
			Total	$ 0.95	$ 1.35

Contributing to the earnings guidance for 2012 are the following items:

We now expect net income to decrease slightly in our Electric segment in 2012 compared with 2011 as a result of the extremely mild weather in the first quarter of 2012. Anticipated increases in rider recovery revenues and capitalized interest costs on higher levels of construction expenditures are expected to be partially offset by lower conservation improvement program incentives and increases in operating and maintenance expenses due to higher postretirement benefit costs.

We expect improvement in operations of our Wind Energy segment to continue in 2012. DMI has been able to stabilize production, improve productivity, align headcount with current production demands and eliminate the need for outsourced quality assurance staffing. Order backlog will continue to support current plant staffing at DMI’s Tulsa and West Fargo plants. DMI continues to experience pricing pressure on new orders due to overcapacity in the U.S. market and significantly lower steel costs available to Asian manufacturers. Backlog in the Wind Energy segment is $114 million for 2012 compared with $134 million one year ago.

We expect earnings from our Manufacturing segment to improve beyond our initial expectations for 2012 due to increased order volume at BTD in excess of initial 2012 projections, continuing improvement in economic conditions in the industries BTD serves, and enhanced performance from T.O. Plastics. Consistent with our initial expectations, ShoreMaster's earnings are still expected to improve over 2011 earnings as a result of bringing costs in line with current revenue levels, improved performance in residential operations and the closure of ShoreMaster's Camdenton, Missouri plant. Camdenton's commercial production operations were consequently relocated to ShoreMaster's Fergus Falls, Minnesota and St. Augustine, Florida facilities. Backlog in place for the manufacturing companies is $111 million for 2012 compared with $87 million one year ago.

We now expect a net loss from our Construction segment in 2012 as Foley continued to experience cost overruns on certain major projects in the first quarter of 2012. Backlog in place for the construction businesses is $83 million for 2012 compared with $105 million one year ago.

We now expect an increase in our Plastics segment net income in 2012 based on the strength of its first quarter performance and current market conditions.

Corporate general and administrative costs are expected to remain relatively flat between the years.

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, percentage-of-completion, warranty 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 60 through 63 of our Annual Report on Form 10-K for the year ended December 31, 2011. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2012.

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 our 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 made a $10.0 million discretionary contribution to our defined benefit pension plan in January 2012. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, 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 and remediation costs in excess of amounts normally reserved for such items could adversely affect our 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.

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.

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.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO_2) 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. The Federal Production Tax Credit is currently scheduled to expire on December 31, 2012.

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. In the fourth quarter of 2011, DMI idled its wind tower production plant in Fort Erie, Ontario. 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, 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.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2012 we had exposure to market risk associated with interest rates because we had $1.1 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 $2.2 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 March 31, 2012 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.

All of our consolidated long-term debt has fixed interest rates. 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.

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 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 March 31, 2012 OTP had recognized, on a pretax basis, $610,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value 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 the 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 contracts that are marked to market as of March 31, 2012, are 97.5% offset by forward energy sales contracts in terms of volumes, delivery periods but not in terms of delivery points. We have recognized a $26,000 loss on the forward energy purchase volume not offset by a forward sales contract. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy 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 March 31, 2012 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 March 31, 2012 and December 31, 2011, and the change in our consolidated balance sheet position from December 31, 2011 to March 31, 2012 and December 31, 2010 to March 31, 2011:

(in thousands)	March 31, 2012	December 31, 2011
Other Current Asset – Derivative Asset	$ 5,391	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	7,268	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	12,770	10,749
Total Assets	25,429	19,760
Derivative Liability	(24,682)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(137)	(96)
Total Liabilities	(24,819)	(18,866)
Fair Value Adjustments Included in Earnings	$ 610	$ 894

(in thousands)	Year-to-Date March 31, 2012	Year-to-Date March 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$ 894	$ 763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(478)	(96)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(32)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	383	635

Changes in Fair Value of Contracts Entered into in Current Period		227		(3)
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$	610	$	632

The $610,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on March 31, 2012 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2nd Qtr 2012	3rd Qtr 2012	4th Qtr 2012	1st Qtr 2013	Total
Net Gain	$ 399	$ 81	$ 95	$ 35	$ 610

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 March 31,	
(in thousands)	2012	2011
Net Gains (Losses) on Forward Electric Energy Contracts	$ 194	$ (8)

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 March 31, 2012 was $1,053,000. As of March 31, 2012 OTP had a net credit risk exposure of $1,793,000 from eight counterparties with investment grade credit ratings. OTP had no exposure at March 31, 2012 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 $1,793,000 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 March 31, 2012. 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 March 31, 2012, 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 March 31, 2012.

During the fiscal quarter ended March 31, 2012, 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

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

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 30 through 37 of the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

Item 6. Exhibits

31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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: May 10, 2012

Exhibit Number	Description
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