Otter Tail Corp
Form 10-Q
August 09, 2012

UNITED STATES
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 June 30, 2012

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to _______________

Commission file number 0-53713

OTTER TAIL CORPORATION
(Exact name of registrant as specified in its charter)

Minnesota	27-0383995
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

215 South Cascade Street, Box 496, Fergus Falls, Minnesota	56538-0496
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act). Yes o No x

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

July 31, 2012 – 36,164,448 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)		June 30, 2012		December 31, 2011
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	--	$	14,652
Accounts Receivable:				
Trade—Net		134,235		116,522
Other		16,602		18,807
Inventories		77,368		77,983
Deferred Income Taxes		12,320		12,307
Accrued Utility Revenues		11,325		13,719
Costs and Estimated Earnings in Excess of Billings		75,295		67,109
Regulatory Assets		25,334		27,391
Other		16,539		21,414
Assets of Discontinued Operations		521		29,692
Total Current Assets		369,539		399,596
Investments		9,056		11,093
Other Assets		27,309		26,997
Goodwill		39,119		39,406
Other Intangibles—Net		14,793		15,286
Deferred Debits				
Unamortized Debt Expense		5,783		6,458
Regulatory Assets		118,672		124,137
Total Deferred Debits		124,455		130,595
Plant				
Electric Plant in Service		1,380,680		1,372,534
Nonelectric Operations		217,391		310,320
Construction Work in Progress		82,523		54,439
Total Gross Plant		1,680,594		1,737,293
Less Accumulated Depreciation and Amortization		630,465		659,744
Net Plant		1,050,129		1,077,549
Total Assets	$	1,634,400	$	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)	June 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$11,274	$--
Current Maturities of Long-Term Debt	50,170	3,033
Accounts Payable	118,954	115,514
Accrued Salaries and Wages	18,490	19,043
Accrued Taxes	8,664	11,841
Derivative Liabilities	20,339	18,770
Other Accrued Liabilities	5,540	5,540
Liabilities of Discontinued Operations	4	13,763
Total Current Liabilities	233,435	187,504
Pensions Benefit Liability	98,620	106,818
Other Postretirement Benefits Liability	49,356	48,263
Other Noncurrent Liabilities	22,150	19,002
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	152,598	177,264
Deferred Tax Credits	32,345	33,182
Regulatory Liabilities	68,071	69,106
Other	538	520
Total Deferred Credits	253,552	280,072
Capitalization		
Long-Term Debt, Net of Current Maturities	421,829	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—36,164,448 Shares; 2011—36,101,695 Shares	180,822	180,509
Premium on Common Shares	253,113	253,123
Retained Earnings	109,267	141,248
Accumulated Other Comprehensive Loss	(3,244)	(3,432)

Total Common Equity	539,958	571,448
Total Capitalization	977,287	1,058,863
Total Liabilities and Equity	$1,634,400	$1,700,522

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating Revenues				
Electric	$78,909	$77,978	$168,847	$169,504
Nonelectric	204,800	205,320	392,451	362,942
Total Operating Revenues	283,709	283,298	561,298	532,446
Operating Expenses				
Production Fuel - Electric	12,455	17,080	27,879	36,657
Purchased Power - Electric System Use	12,328	7,894	26,486	20,271
Electric Operation and Maintenance Expenses	32,407	28,687	62,420	57,395
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	167,612	179,241	330,602	319,580
Other Nonelectric Expenses	17,189	17,014	34,680	30,090
Asset Impairment Charge	45,573	--	46,005	--
Depreciation and Amortization	17,118	17,552	34,171	34,658
Property Taxes - Electric	2,670	2,417	5,287	4,826
Total Operating Expenses	307,352	269,885	567,530	503,477
Operating (Loss) Income	(23,643)	13,413	(6,232)	28,969
Interest Charges	8,477	9,138	17,093	18,614
Other Income	741	765	1,734	1,136
(Loss) Income from Continuing Operations Before Income Taxes	(31,379)	5,040	(21,591)	11,491
Income Tax (Benefit) Expense – Continuing Operations	(14,493)	(85)	(14,196)	1,153
Net (Loss) Income from Continuing Operations	(16,886)	5,125	(7,395)	10,338
Discontinued Operations				
(Loss) Income - net of Income Tax (Benefit) Expense of ($11), $280, $573, and $568 for the respective periods	(15)	451	826	934
(Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of ($35), $3,515, ($169), and $3,515 for the respective periods	(455)	13,252	(3,544)	13,252
Net (Loss) Income from Discontinued Operations	(470)	13,703	(2,718)	14,186
Net (Loss) Income	(17,356)	18,828	(10,113)	24,524
Preferred Dividend Requirements and Other Adjustments	184	506	368	690
Earnings Available for Common Shares	$(17,540)	$18,322	$(10,481)	$23,834
Average Number of Common Shares Outstanding—Basic	36,031,447	35,926,124	36,013,313	35,901,489
Average Number of Common Shares Outstanding—Diluted	36,031,447	36,163,805	36,013,313	36,139,170
Basic Earnings Per Common Share:				
Continuing Operations	$(0.48)	$0.14	$(0.22)	$0.28
Discontinued Operations	(0.01)	0.37	(0.07)	0.38

	$(0.49)	$0.51	$(0.29)	$0.66
Diluted Earnings Per Common Share:				
Continuing Operations	$(0.48)	$0.14	$(0.22)	$0.28
Discontinued Operations	(0.01)	0.37	(0.07)	0.38
	$(0.49)	$0.51	$(0.29)	$0.66
Dividends Declared Per Common Share	$0.2975	$0.2975	$0.5950	$0.5950

See accompanying notes to consolidated financial statements.

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

(in thousands)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net (Loss) Income	$(17,356)	$18,828	$(10,113)	$24,524
Other Comprehensive Income (Loss):				
Unrealized Gain on Available-for-Sale Securities:				
Gain Arising During Period	4	31	108	14
Income Tax Expense	(2)	(13)	(43)	(6)
Unrealized Gain on Available-for-Sale Securities – net-of-tax	2	18	65	8
Foreign Currency Translation Adjustment:				
Unrealized Net Change During Period	--	(342)	--	303
Reversal of Previously Recognized Gains Realized on the Sale of Idaho Pacific Holdings, Inc. (IPH)	--	(6,068)	--	(6,068)
Income Tax Benefit	--	1,988	--	1,788
Foreign Currency Translation Adjustment – net-of-tax	--	(4,422)	--	(3,977)
Pension and Postretirement Benefit Plans:				
Actuarial Loss -- Regulatory Allocation Adjustment (ESSRP)	--	--	--	(1,621)
Amortization of Unrecognized Postretirement Benefit Losses and Costs	102	713	204	884
Income Tax (Expense) Benefit	(40)	(285)	(81)	295
Pension and Postretirement Benefit Plans – net-of-tax	62	428	123	(442)
Total Other Comprehensive Income (Loss)	64	(3,976)	188	(4,411)
Total Comprehensive (Loss) Income	$(17,292)	$14,852	$(9,925)	$20,113

See accompanying notes to consolidated financial statements.

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

(in thousands)	Six Months Ended June 30, 2012	2011
Cash Flows from Operating Activities		
Net (Loss) Income	$(10,113)	$24,524
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Loss (Gain) from Sale of Discontinued Operations	3,544	(13,252)
Income from Discontinued Operations	(826)	(934)
Depreciation and Amortization	34,171	34,658
Asset Impairment Charge	46,005	--
Deferred Tax Credits	(1,045)	(1,281)
Deferred Income Taxes	(9,632)	5,650
Change in Deferred Debits and Other Assets	9,960	7,648
Discretionary Contribution to Pension Plan	(10,000)	--
Change in Noncurrent Liabilities and Deferred Credits	6,095	1,212
Allowance for Equity (Other) Funds Used During Construction	(378)	(292)
Change in Derivatives Net of Regulatory Deferral	748	45
Stock Compensation Expense – Equity Awards	612	921
Other—Net	453	654
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(15,508)	(30,298)
Change in Inventories	615	(6,235)
Change in Other Current Assets	(10,917)	(2,743)
Change in Payables and Other Current Liabilities	6,905	8,967
Change in Interest and Income Taxes Receivable/Payable	(6,549)	(162)
Net Cash Provided by Continuing Operations	44,140	29,082
Net Cash Provided by Discontinued Operations	1,377	11,655
Net Cash Provided by Operating Activities	45,517	40,737
Cash Flows from Investing Activities		
Capital Expenditures	(69,443)	(39,777)
Proceeds from Disposal of Noncurrent Assets	5,560	1,233
Net (Increase) Decrease in Other Investments	(268)	937
Net Cash Used in Investing Activities - Continuing Operations	(64,151)	(37,607)
Net Proceeds from Sale of Discontinued Operations	24,278	84,363
Net Cash Used in Investing Activities - Discontinued Operations	(11,705)	(13,503)
Net Cash (Used in) Provided by Investing Activities	(51,578)	33,253
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	7,352	(5,627)
Net Short-Term Borrowings (Repayments)	11,274	(46,777)
Payments for Retirement of Common Stock and Common Stock Issuance Expenses	(196)	(152)
Proceeds from Issuance of Long-Term Debt	--	2,007
Short-Term and Long-Term Debt Issuance Expenses	(10)	(688)
Payments for Retirement of Long-Term Debt	(2,949)	(167)
Dividends Paid and Other Distributions	(21,980)	(21,952)
Net Cash Used in Financing Activities - Continuing Operations	(6,509)	(73,356)
Net Cash Used in Financing Activities - Discontinued Operations	(1,409)	(310)

Net Cash Used in Financing Activities	(7,918)	(73,666)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(673)	--
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	--	(324)
Net Change in Cash and Cash Equivalents	(14,652)	--
Cash and Cash Equivalents at Beginning of Period	14,652	--
Cash and Cash Equivalents at End of Period	$--	$--

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 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 and six month periods ended June 30, 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Percentage-of-Completion Revenues	36.2 %	38.0 %	34.2 %	36.8 %

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

(in thousands)	June 30, 2012	December 31, 2011
Costs Incurred on Uncompleted Contracts	$533,627	$583,346
Less Billings to Date	(500,959)	(550,070)
Plus Estimated Earnings Recognized	27,299	24,478
Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts	$59,967	$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)	June 30, 2012	December 31, 2011
Costs and Estimated Earnings in Excess of Billings	$75,295	$67,109
Billings in Excess of Costs and Estimated Earnings	(15,328)	(9,355)
Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts	$59,967	$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)	June 30, 2012	December 31, 2011
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts - DMI	$61,834	$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		426
Settlements Made During the Year		(552)
Adjustments to Warranty Estimates for Prior Years		(38)
Warranty Reserve Balance, June 30, 2012	$	3,006

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)	June 30, 2012	December 31, 2011
Accounts Receivable Retained by Customers	$14,390	$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 (GECC) on a revolving basis. This agreement was terminated effective April 26, 2012. 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 under DMI's receivables sales agreement with GECC:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Accounts Receivable Sold	$11,087	$9,092	$32,115	$28,140

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 June 30, 2012 and December 31, 2011:

June 30, 2012 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$2,402	
Forward Gasoline Purchase Contracts		27	
Money Market Fund - Escrow Account IPH Sale	1,500		
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,114	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,303	
Other Assets:			

Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	734	
Equity Securities - Nonqualified Retirement Savings Plan	127	
Total Assets	$2,471	$10,846
Liabilities:		
Derivative Liabilities:		
Forward Energy Contracts	$--	$20,337
Forward Gasoline Purchase Contracts		2
Total Liabilities	$--	$20,339

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.

December 31, 2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$3,803	
Forward Gasoline Purchase Contracts	9		
Money Market Fund - Escrow Account IPH Sale	1,500		
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Regulatory Assets – Current:			
Deferred Mark-to-Market Losses on Forward Energy Contracts		5,208	
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		8,083	
U.S. Government Debt Securities – Held by Captive Insurance Company	707		
Money Market Fund - Escrow Account IPH Sale	1,501		
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	254		
Regulatory Assets – Deferred:			
Deferred Mark-to-Market Losses on Forward Energy Contracts		10,749	
Total Assets	$4,081	$27,843	
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$18,770	
Regulatory Liabilities – Current:			
Deferred Mark-to-Market Gains on Forward Energy Contracts		96	
Total Liabilities	$--	$18,866	

Inventories

Inventories consist of the following:

(in thousands)	June 30, 2012	December 31, 2011
Finished Goods	$ 24,333	$ 21,373
Work in Process	11,365	11,951
Raw Material, Fuel and Supplies	41,670	44,659
Total Inventories	$ 77,368	$ 77,983

Asset Impairment Charge

The Company entered into a nonbinding letter of interest in June 2012 to sell the property, plant and equipment of DMI for $20 million, with the Company retaining DMI’s net working capital—approximately $66 million on June 30, 2012. The transaction is expected to close no later than January 3, 2013. The market value for DMI’s assets has been significantly impacted by reduced demand for wind towers due to adverse market conditions affecting the industry, including uncertainty regarding renewal or extension of the Federal Production Tax Credit (PTC) for investments in renewable energy resources, which is set to expire at the end of 2012. Based on the Company’s second quarter 2012 decision to divest DMI’s assets and the price for the fixed assets agreed to in the nonbinding letter of interest, DMI recorded a noncash asset impairment charge of $45.6 million ($27.5 million net-of-tax), or $0.76 per share, in the second quarter of 2012 broken down as follows:

(in thousands)		
Long-Lived Assets	$	90,846
Accumulated Depreciation – Long-Lived Assets		(45,561)
Goodwill		288
Total Asset Impairment Charges	$	45,573

Under the terms of the nonbinding letter of interest, DMI must complete its current backlog of towers ordered for delivery in 2012 before closing can occur. Under these circumstances, accounting rules require that DMI's assets and results of operations continue to be reported as continuing operations. However, on completion of all remaining tower orders, DMI's assets will be considered available for immediate sale and the Company expects DMI's results and any remaining assets will be reported as discontinued operations at the end of 2012. Should the transaction not be completed, the Company plans to close DMI's plants in West Fargo, North Dakota and Tulsa, Oklahoma and sell DMI's fixed assets, after DMI finishes its backlog of orders for 2012.

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) June 30, 2012
Electric	$ 240	$ (240)	$ --	$ --	$ --
Wind Energy	288	--	288	(288)	--
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	1	7,631
Plastics	19,302	--	19,302	--	19,302
Total	$ 51,905	$ (12,499)	$ 39,406	$ (287)	$ 39,119

Other Intangible Assets
The following table summarizes the components of the Company’s intangible assets at June 30, 2012 and December 31, 2011:

June 30, 2012 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 3,661	$ 13,150	15 – 25 years
Other Intangible Assets Including Contracts	1,092	549	543	5 – 30 years
Total	$ 17,903	$ 4,210	$ 13,693	
Indefinite-lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	
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	1,092	485	607	5 – 30 years
Total	$ 18,616	$ 4,430	$ 14,186	
Indefinite-lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	

The amortization expense for these intangible assets was:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Amortization Expense – Intangible Assets	$246	$218	$493	$442

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

	As of June 30,	
(in thousands)	2012	2011
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions	$6,558	$1,326

Reclassifications and Changes to Presentation
The Company's consolidated statements of income for the three and six month periods ended June 30, 2011 and consolidated statement of cash flows for the six months ended June 30, 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 or six month periods ended June 30, 2011.

2. Segment Information

The Company's businesses have been classified into five reportable 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
United States of America	97.5 %	97.9 %	97.7 %	98.3 %
Canada	1.6 %	1.9 %	1.5 %	1.5 %
All Other Countries	0.9 %	0.2 %	0.8 %	0.2 %

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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 and six month periods ended June 30, 2012 and total assets by business segment as of June 30, 2012 and December 31, 2011 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Electric	$78,963	$78,031	$168,966	$169,627
Wind Energy	62,618	55,025	114,720	102,013
Manufacturing	63,581	57,320	129,575	112,681
Construction	37,934	49,133	73,551	86,648
Plastics	41,490	44,373	76,365	62,851
Corporate Revenues and Intersegment Eliminations	(877)	(584)	(1,879)	(1,374)
Total	$283,709	$283,298	$561,298	$532,446

Interest Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Electric	$4,762	$4,990	$9,613	$10,078
Wind Energy	1,614	1,858	3,314	3,559
Manufacturing	1,353	1,255	2,689	2,466
Construction	310	227	563	447
Plastics	346	402	692	765
Corporate and Intersegment Eliminations	92	406	222	1,299
Total	$8,477	$9,138	$17,093	$18,614

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Electric	$(800)	$8	$822	$2,608
Wind Energy	(15,811)	(2,174)	(15,967)	(3,723)
Manufacturing	1,658	1,562	3,127	3,352
Construction	(1,164)	130	(3,940)	(80)
Plastics	2,722	2,144	4,897	1,903
Corporate	(1,098)	(1,755)	(3,135)	(2,907)
Total	$(14,493)	$(85)	$(14,196)	$1,153

Earnings Available for Common Shares

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011

Electric	$5,191	$7,386	$16,207	$18,528
Wind Energy	(24,933)	(6,566)	(25,623)	(12,798)
Manufacturing	2,420	2,769	4,631	5,427
Construction	(1,756)	184	(5,927)	(141)
Plastics	4,067	3,312	7,320	2,938
Corporate	(2,059)	(2,144)	(4,371)	(3,984)
Discontinued Operations	(470)	13,381	(2,718)	13,864
Total	$(17,540)	$18,322	$(10,481)	$23,834

Identifiable Assets

(in thousands)	June 30, 2012	December 31, 2011
Electric	$ 1,168,902	$ 1,170,449
Wind Energy	113,736	149,234
Manufacturing	155,865	154,908
Construction	68,407	69,453
Plastics	87,747	72,200
Corporate	39,222	54,586
Discontinued Operations	521	29,692
Total	$ 1,634,400	$ 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 authorized rates of return are 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. The 2010 MNRRA was in place from September 1, 2010 through September 30, 2011 with a recovery of $17.0 million.

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. OTP has a regulatory asset of $2.0 million for revenues that are eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of June 30, 2012. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by revised filing on July 25, 2012. The filing included a request to extend the period of the new rate for 18 months, which would reduce the current balance of unrecovered costs to zero.

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 $0.2 million for revenues that are eligible for recovery through the Minnesota TCR rider that have not been billed to Minnesota customers as of June 30, 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, approved by the MPUC on March 26, 2012, went into effect April 1, 2012.

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 MPUC 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 MPUC approved using the all-in method on March 26, 2012.

On May 24, 2012, OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. If approval is obtained to include projects in the rider, investment in the approved projects will be included in the annual Minnesota TCR rider update filings and recovery of the investment will begin through the TCR rider rates if subsequently approved by the MPUC.

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.

OTP has a regulatory asset of $6.2 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of June 30, 2012. OTP recognized revenue for Minnesota conservation costs earned totaling $0.9 million and $1.7 million, respectively, in the three and six month periods ended June 30, 2012, compared with $1.2 million and $3.0 million, respectively, in the three and six month periods ended June 30, 2011.

North Dakota

Renewable Resource Cost Recovery Rider—The 2010 North Dakota Renewable Resource Adjustment (NDRRA) was in place for the period of September 1, 2010 through March 31, 2012 with a recovery of $15.6 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with an April 1, 2012 effective date. OTP's request for an updated NDRRA was approved by the North Dakota Public Service Commission (NDPSC) on March 21, 2012 and went into effect April 1, 2012. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 through March 31, 2013. OTP has a regulatory asset of $1.3 million for revenues that are eligible for recovery through the NDRRA rider that have not been billed to North Dakota customers as of June 30, 2012.

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 and the rider rate to be effective May 1, 2012. OTP has a regulatory asset of $1.1 million for revenues that are eligible for recovery through the North Dakota TCR rider that have not been billed to North Dakota customers as of June 30, 2012.

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.

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 (MISO Tariff). OTP was also authorized by the FERC to recover: (1) in its formula rate 100% of prudently incurred Construction Work in Progress (CWIP) in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, 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, Seventh 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.

The Big Stone South – Brookings Project—OTP is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. OTP expects, in the third quarter of 2012, to file a request with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. OTP and Xcel Energy expect to make a joint route permit filing in the first quarter of 2013 for the remaining portion of the project.

The Ellendale – Big Stone South Project—OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. This project will require regulatory approval from both the SDPUC and the NDPSC. Route permits are expected to be filed with the respective commissions in the third quarter of 2013.

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 230 kV 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 (the Brookings Project as an MVP) 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.

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 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 during the third 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. This line is expected to be in service before the end 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 August 6, 2012 a Consent Order Approving Stipulation for Entry of Consent Decree was issued in federal court, which enjoins the LLBO from interfering with the construction, operation, maintenance or repair of the transmission line. The federal litigation is now concluded. In conjunction with the stipulated agreement, the tribal court dismissed the LLBO's action and the LLBO has withdrawn its petition to the MPUC.

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, with an effective date of 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 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 filed an application for an ADP with the NDPSC on May 20, 2011, and the NDPSC approved OTP's request for an ADP on May 9, 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 AQCS 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. Information requests for this filing were received on July 13, 2012.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

(in thousands)	June 30, 2012 Current	June 30, 2012 Long-Term	June 30, 2012 Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 7,047	$ 91,808	$ 98,855	see notes
Deferred Marked-to-Market Losses	6,952	11,175	18,127	38 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	2,456	3,724	6,180	24 months
Accumulated ARO Accretion/Depreciation Adjustment	--	3,895	3,895	asset lives
Big Stone II Unrecovered Project Costs – Minnesota	510	1,885	2,395	51 months
Debt Reacquisition Premiums	273	2,113	2,386	243 months
Accrued Cost-of-Energy Revenues	2,065	--	2,065	12 months
Deferred Income Taxes	--	2,018	2,018	asset lives
Minnesota Renewable Resource Rider Accrued Revenues	1,007	960	1,967	21 months
Big Stone II Unrecovered Project Costs – North Dakota	1,388	157	1,545	13 months
North Dakota Renewable Resource Rider Accrued Revenues	1,264	79	1,343	21 months
North Dakota Transmission Rider Accrued Revenues	1,103	--	1,103	12 months
Big Stone II Unrecovered Project Costs – South Dakota	100	761	861	103 months
General Rate Case Recoverable Expenses	596	42	638	19 months
Minnesota Transmission Rider Accrued Revenue	208	--	208	12 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	156	--	156	5 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	126	--	126	6 months
Deferred Holding Company Formation Costs	55	55	110	24 months
South Dakota Transmission Rider Accrued Revenues	28	--	28	6 months
Total Regulatory Assets	$ 25,334	$ 118,672	$ 144,006	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 64,996	$ 64,996	asset lives
Deferred Income Taxes	--	2,961	2,961	asset lives

Deferred Gain on Sale of Utility Property – Minnesota Portion	6	114	120	258 months
South Dakota – Nonasset-Based Margin Sharing Excess	72	--	72	6 months
Deferred Marked-to-Market Gains	61	--	61	8 months
Total Regulatory Liabilities	$ 139	$ 68,071	$ 68,210	
Net Regulatory Asset Position	$ 25,195	$ 50,601	$ 75,796	

	December 31, 2011			Remaining Recovery/ Refund
(in thousands)	Current	Long-Term	Total	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 June 30, 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 243 months.

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.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through June 30, 2012 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of June 30, 2012.

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 June 30, 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 June 30, 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 June 30, 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 June 30, 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 June 30, 2012 and December 31, 2011, and the change in the Company's consolidated balance sheet position from December 31, 2011 to June 30, 2012 and December 31, 2010 to June 30, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Other Current Asset – Derivative Asset	$ 2,402	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	6,952	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	11,175	10,749
Total Assets	20,529	19,760
Derivative Liability	(20,337)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(61)	(96)
Total Liabilities	(20,398)	(18,866)
Fair Value Adjustments Included in Earnings	$ 131	$ 894

(in thousands)	Year-to-Date June 30, 2012	Year-to-Date June 30, 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	(700)	(151)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	161	526
Changes in Fair Value of Contracts Entered into in Current Period	(30)	120
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 131	$ 646

The recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2012 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	3rd Qtr 2012	4th Qtr 2012	1st Qtr 2013	Total
Net Gain	$ 5	$ 123	$ 3	$ 131

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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:

(in thousands)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net Gains (Losses) on Forward Electric Energy Contracts	$ (50)	$ 139	$ 144	$ 131

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 June 30, 2012 and December 31, 2011:

	June 30, 2012		December 31, 2011	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$860	8	$1,677	10
Net Credit Risk to Single Largest Counterparty	$348		$737	

OTP had a net credit risk exposure to eight counterparties with investment grade credit ratings. OTP had no exposure at June 30, 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 June 30, 2012 and December 31, 2011:

Current Liability – Marked-to-Market Loss (in thousands)	June 30, 2012	December 31, 2011
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 2,000	$ 3,423
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	18,337	15,347
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$ 20,337	$ 18,770
1Certain 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	$ 18,337	$ 15,347
Offsetting Gains with Counterparties under Master Netting Agreements	(2,355)	(3,471)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 15,982	$ 11,876

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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 June 30, 2012:

Common Shares Outstanding, December 31, 2011	36,101,695
Issuances:	
Restricted Stock Issued to Employees	24,500
Restricted Stock Issued to Nonemployee Directors	24,000
Vesting of Restricted Stock Units	21,150
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(5,072)
Forfeiture of Unvested Restricted Stock	(1,825)
Common Shares Outstanding, June 30, 2012	36,164,448

Earnings Per Share

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

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

Three Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2012	92,497	\$24.93 – \$27.25
2011	172,460	\$24.93 – \$31.34

Six Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2012	92,497	\$24.93 – \$27.25
2011	172,460	\$24.93 – \$31.34

7. Share-Based Payments

The Company has five share-based payment programs.

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.

As of June 30, 2012 the remaining unrecognized compensation expense related to stock-based compensation was approximately $4.1 million (before income taxes) which will be amortized over a weighted-average period of 2.7 years.

Compensation expense recognized under the Company's stock-based payment programs are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Employee Stock Purchase Plan (15% discount)	$ 49	$ 72	$ 88	$ 134

Restricted Stock Granted to Directors	138	195	274	387
Restricted Stock Granted to Employees	87	133	145	248
Restricted Stock Units Granted to Employees	51	70	105	153
Stock Performance Awards Granted to Executive Officers	293	--	293	--
Totals	$ 618	$ 470	$ 905	$ 922

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 June 30, 2012.

9. Commitments and Contingencies

Construction Commitments
At December 31, 2011 OTP had commitments under contracts in connection with construction programs aggregating approximately $41.0 million for 2012. OTP's share of additional commitments under contracts entered into in 2012 related to CapX2020 transmission projects, the Big Stone AQCS project, and a water handling project at Coyote Station increased its total construction commitments as of June 30, 2012 by $18.7 million for the remainder of 2012, $21.9 million for 2013, $4.2 million for 2014 and $19.5 million for 2015.

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 six months 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 six months of 2012.

Commitment for Development of New Coal Source for Coyote Station
Coyote Station owners, including OTP, entered into an agreement on May 1, 2012 with the North American Coal Corporation for pre-commencement development work at Coyote Creek Mine near Coyote Station. OTP's current share of the Coyote Station owners' commitment to develop Coyote Creek Mine is for up to $0.9 million plus any interest or capital charges. All applicable development work is to be completed in 2012. If the lignite sales agreement (LSA) currently under negotiation is signed, the pre-contract development costs will be paid over a 52-month period starting in May 2016 when the first coal would be delivered under the LSA. If the LSA is not signed, the Coyote Station owners can terminate development activities and would be billed for all pre-contract costs incurred with payment due within 30 days of receipt of the invoice.

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 June 30, 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 all of these items result in a liabilities being incurred, the 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 June 30, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on June 30, 2012	Restricted due to Outstanding	Available on June 30, 2012	Available on December 31, 2011

			Letters of Credit		
Otter Tail Corporation Credit Agreement1	$200,000	$ 2,289	$ 850	$ 196,861	$ 198,776
OTP Credit Agreement	170,000	8,985	3,050	157,965	165,950
Total	$370,000	$ 11,274	$ 3,900	$ 354,826	$ 364,726

1 On July 13, 2012 the Company used funds available under the Otter Tail Corporation Credit Agreement to repay in full the $50 million Cascade Note referred to in Note 18 – Subsequent Events.

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Long-Term Debt Retirement
In April 2012, ShoreMaster, Inc. (ShoreMaster), a wholly owned subsidiary of Varistar Corporation, exercised a purchase option on a building it had been leasing under a capital lease and paid off the remaining $2.8 million balance of its lease obligation.

The following tables provide a breakdown of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2012 and December 31, 2011:

June 30, 2012 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$8,985	$--	$ 2,289	$ 11,274
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[1]			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 June 30, 2012			1,808	1,808
Total	$320,195	$--	$ 151,808	$ 472,003
Less: Current Maturities[1]	--	--	50,170	50,170
Unamortized Debt Discount	--	--	4	4
Total Long-Term Debt	$320,195	$--	$ 101,634	$ 421,829
Total Short-Term and Long-Term Debt (with current maturities)	$329,180	$--	$ 154,093	$ 483,273

[1]On July 13, 2012 the Company used funds available under the Otter Tail Corporation Credit Agreement to repay in full the $50 million Cascade Note referred to in Note 18 – Subsequent Events.

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	5,090			5,090

Refunding Revenue Bonds 4.65%, due September 1, 2017				
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 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Service Cost—Benefit Earned During the Period	$ 1,248	$ 1,175	$ 2,542	$ 2,350
Interest Cost on Projected Benefit Obligation	3,125	3,175	6,233	6,350
Expected Return on Assets	(3,607)	(3,538)	(7,215)	(7,075)
Amortization of Prior-Service Cost	102	100	204	200
Amortization of Net Actuarial Loss	1,289	650	2,520	1,300
Net Periodic Pension Cost	$ 2,157	$ 1,562	$ 4,284	$ 3,125

Cash flows—The Company had a minimum pension plan 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, and has not made, any additional contributions in 2012. The Company did not make a contribution to its pension plan in the six months ended June 30, 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Service Cost—Benefit Earned During the Period	$ 12	$ 21	$ 23	$ 41
Interest Cost on Projected Benefit Obligation	369	408	739	816
Amortization of Prior-Service Cost	19	18	37	37
Amortization of Net Actuarial Loss	81	61	163	122
Net Periodic Pension Cost	$ 481	$ 508	$ 962	$ 1,016

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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Service Cost—Benefit Earned During the Period	$ 439	$ 425	$ 900	$ 850
Interest Cost on Projected Benefit Obligation	869	850	1,750	1,700
Amortization of Transition Obligation	187	187	374	374
Amortization of Prior-Service Cost	53	50	105	100

Amortization of Net Actuarial Loss	368	213	759	426
Effect of Medicare Part D Expected Subsidy	(533)	(525)	(1,020)	(1,050)
Net Periodic Postretirement Benefit Cost	$ 1,383	$ 1,200	$ 2,868	$ 2,400

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 fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820, Fair Value Measurement.

(in thousands)	June 30, 2012 Carrying Amount	June 30, 2012 Fair Value	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value
Cash and Cash Equivalents	$--	$--	$14,652	$14,652
Long-Term Debt (including current maturities)	$(471,999)	$(532,927)	$(474,948)	$(528,074)

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 and six month periods ended June 30, 2012 and 2011:

(in thousands)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
(Loss) Income Before Income Taxes – Continuing Operations	$(31,379)	$5,040	$(21,591)	$11,491
Add Back Canadian Losses not Subject to Income Tax Benefits	917	3,283	1,368	6,780
(Loss) Income Before Income Taxes – Continuing Operations, Subject to Taxes	(30,462)	8,323	(20,223)	18,271
Income Tax (Benefit) Expense Computed at the Company's Net Composite Federal and State Statutory Rate (39%)	(11,880)	3,246	(7,887)	7,126
Increases (Decreases) in Tax from:				
Federal Production Tax Credits	(1,831)	(1,929)	(3,818)	(3,905)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	--	--	(676)	--
Corporate Owned Life Insurance	(13)	(178)	(385)	(266)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(149)	(265)	(371)	(555)
Medicare Part D Subsidy	(194)	(169)	(391)	(361)
Employee Stock Ownership Plan Dividend Deduction	(191)	(190)	(381)	(384)
Canadian Revenue Authority Audit Settlement	--	--	--	156
Investment Tax Credit	(180)	(214)	(360)	(427)
Other Items – Net	(55)	(386)	73	(231)
Income Tax (Benefit) Expense – Continuing Operations	$(14,493)	$(85)	$(14,196)	$1,153
Effective Income Tax Rate – Continuing Operations	46.2 %	(1.7)%	65.7 %	10.0 %

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	2012
Balance on January 1	$ 12,138
	--

Increases Related to Tax Positions for Prior Years		
Uncertain Positions Resolved During Year		(8,354)
Balance on June 30	$	3,784

The balance of unrecognized tax benefits as of June 30, 2012 would not reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2012 is not expected to change significantly within the next six months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. No interest is accrued on tax uncertainties as of June 30, 2012.

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, of which $1.5 million was released to the Company in May 2012. 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 and six month periods ended June 30, 2012 and 2011:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Operating Revenues	$ --	$ 41,282	$ 16,352	$ 99,460
Operating Expenses	26	41,799	14,928	99,343
Operating (Loss) Income	(26)	(517)	1,424	117
Interest Charges	--	11	147	31
Other Income	--	1,259	122	1,416
Income Tax (Benefit) Expense	(11)	280	573	568
Net (Loss) Income from Operations	(15)	451	826	934
(Loss) Gain on Disposition Before Taxes	(490)	16,767	(3,713)	16,767
Income Tax (Benefit) Expense on Disposition	(35)	3,515	(169)	3,515
Net (Loss) Gain on Disposition	(455)	13,252	(3,544)	13,252
Net (Loss) Income	$ (470)	$ 13,703	$ (2,718)	$ 14,186

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of June 30, 2012 and December 31, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Current Assets	$ 521	$ 29,320
Net Plant	--	372
Assets of Discontinued Operations	$ 521	$ 29,692
Current Liabilities	$ 236	$ 14,740
Deferred Income Taxes	(232)	(1,811)
Deferred Credits - Other	--	119
Long-Term Debt	--	715
Liabilities of Discontinued Operations	$ 4	$ 13,763

18. Subsequent Events

Early Repayment of Debt

On July 13, 2012 the Company prepaid in full its outstanding $50 million, 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note) issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between the Company and Cascade Investment, L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by the Company to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. The Company used funds available under the Otter Tail Corporation Credit Agreement for the prepayment. This early retirement reflects the Company's desire to lower its long-term debt outstanding given its recent divestitures and its anticipated divestiture of DMI. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 negotiated prepayment premium, which will reduce diluted earnings per share by $0.22 in 2012. The $50,000,000 of debt retired on July 13, 2012 was included in current maturities of long-term debt on the Company's June 30, 2012 consolidated balance sheet. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2011.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and six month periods ended June 30, 2012 and 2011, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2012 and our business outlook for the remainder of 2012.

Comparison of the Three Months Ended June 30, 2012 and 2011

Consolidated operating revenues were $283.7 million for the three months ended June 30, 2012 compared with $283.3 million for the three months ended June 30, 2011. Operating loss was $23.6 million for the three months ended June 30, 2012 compared with operating income of $13.4 million for the three months ended June 30, 2011. The Company recorded diluted earnings per share from continuing operations of ($0.48) for the three months ended June 30, 2012 compared to $0.14 for the three months ended June 30, 2011 and total diluted earnings per share of ($0.49) for the three months ended June 30, 2012 compared to $0.51 for the three months ended June 30, 2011.

Asset Impairment Charge—We entered into a nonbinding letter of interest in June 2012 to sell the property, plant and equipment of DMI Industries, Inc. (DMI) for $20 million, while retaining DMI's net working capital—approximately $66 million on June 30, 2012. The transaction is expected to close no later than January 3, 2013. The market value for DMI's assets has been significantly impacted by reduced demand for wind towers due to adverse market conditions affecting the industry, including uncertainty regarding renewal or extension of the Federal Production Tax Credit (PTC) for investments in renewable energy resources, which is set to expire at the end of 2012. Based on our second quarter 2012 decision to divest DMI's assets and the price for the fixed assets agreed to in the nonbinding letter of interest, DMI recorded a noncash asset impairment charge of $45.6 million ($27.5 million net-of-tax), or $0.76 per share, in the second quarter of 2012 broken down as follows:

(in thousands)		
Long-Lived Assets	$	90,846
Accumulated Depreciation – Long-lived Assets		(45,561)
Goodwill		288
Total Asset Impairment Charge	$	45,573

Under the terms of the nonbinding letter of interest, DMI must complete its current backlog of towers ordered for delivery in 2012 before closing can occur. Under these circumstances, accounting rules require that DMI's assets and results of operations continue to be reported as continuing operations. However, on completion of all remaining tower orders, DMI's assets will be considered available for immediate sale and we expect DMI's results and any remaining assets will be reported as discontinued operations at the end of 2012. Should the transaction not be completed, we plan to close DMI's plants in West Fargo, North Dakota and Tulsa, Oklahoma and sell DMI's fixed assets, after DMI finishes its backlog of orders for 2012.

Intersegment Eliminations—Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended June 30, 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)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011

Operating Revenues:		
Electric	$ 54	$ 53
Nonelectric	823	531
Cost of Goods Sold	830	557
Other Nonelectric Expenses	47	27

Electric

(in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Retail Sales Revenue	$ 68,719	$ 67,702	$ 1,017	1.5
Wholesale Revenue – Company Generation	2,028	3,563	(1,535)	(43.1)
Net Revenue – Energy Trading Activity	561	750	(189)	(25.2)
Other Revenue	7,655	6,016	1,639	27.2
Total Operating Revenues	$ 78,963	$ 78,031	$ 932	1.2
Production Fuel	12,455	17,080	(4,625)	(27.1)
Purchased Power – System Use	12,328	7,894	4,434	56.2
Other Operation and Maintenance Expenses	32,407	28,687	3,720	13.0
Depreciation and Amortization	10,447	10,020	427	4.3
Property Taxes	2,670	2,417	253	10.5
Operating Income	$ 8,656	$ 11,933	$ (3,277)	(27.5)

Electric kwh Sales (in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Retail kilowatt-hour (kwh) Sales	907,529	951,527	(43,998)	(4.6)
Wholesale kwh Sales – Company Generation	71,364	147,799	(76,435)	(51.7)
Wholesale kwh Sales – Purchased Power Resold	58,632	29,481	29,151	98.9

The $1.0 million increase in retail sales revenue reflects the following:

a $1.8 million increase in revenue mainly related to rate design changes implemented in Minnesota in October 2011 on finalization of Otter Tail Power Company's (OTP) 2010 general rate case,

a $1.0 million increase in revenue related to the recovery of an increase in the average cost of fuel and purchased power per kwh incurred to serve retail customers, and

a $0.7 million increase in transmission costs recovery rider revenue as a result of increased investment in transmission assets,

offset by:

a $2.5 million decrease in revenue, mainly due to a 4.6% reduction in retail kwh sales primarily resulting from significantly milder weather in the second quarter of 2012 as heating degree days were down 28.0% compared with the second quarter of 2011.

Wholesale electric revenue from company-owned generation decreased $1.5 million as a result of a 51.7% decrease in wholesale kwh sales. Lower wholesale demand due to milder weather drove wholesale prices down, reducing opportunities to sell competitively in wholesale markets. Additionally, OTP's plant availability was reduced in the second quarter of 2012 as Coyote Station, OTP's lowest fuel-cost plant, was shut down for seven weeks of scheduled maintenance and Big Stone Plant had a 10-day spring maintenance outage, resulting in a 34.9% reduction in kwhs generated from OTP's steam-powered and combustion turbine generators.

Other electric operating revenue increased $1.6 million mainly as a result of an increase in transmission tariff revenues, due, in part, to revenues from CapX2020 transmission project investments.

Fuel costs decreased $4.6 million as a result of the 34.9% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 12.0% increase in the cost of fuel per kwh generated. Generation levels decreased in response to lower demand due to mild weather and because of scheduled plant maintenance outages. The cost of purchased power for retail sales increased $4.4 million as a result of a 121% increase in kwhs purchased, partially offset by a 29.2% decrease in the cost per kwh purchased. The increase in kwhs purchased was mainly due to the reduced availability of OTP's steam-powered generators.

Electric operating and maintenance expenses increased $3.7 million due to the following:

a $1.8 million increase in generation plant maintenance costs mainly related to the seven-week scheduled maintenance shutdown of Coyote Station in the second quarter of 2012,

a $1.2 million increase in employee benefit expenses mainly due to increases in postretirement benefit costs resulting from a reduction in the discount rate related to projected benefit obligations, and

a $0.7 million increase in Midwest Independent Transmission System Operator (MISO) Schedule 26 transmission service charges.

The $0.4 million increase in Electric segment depreciation expense is related to 2011 property additions. The $0.3 million increase in property taxes is due to higher taxes on electric distribution property along with increased investments in transmission property.

Wind Energy

(in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Revenues	$ 62,618	$ 55,025	$ 7,593	13.8
Cost of Goods Sold	51,990	56,012	(4,022)	(7.2)
Operating Expenses	2,209	3,116	(907)	(29.1)
Asset Impairment Charge	45,573	--	45,573	--
Depreciation and Amortization	2,073	2,798	(725)	(25.9)
Operating Loss	$ (39,227)	$ (6,901)	$ (32,326)	(468.4)

Revenues at DMI’s U.S. plants increased $16.7 million due to an 8.8% increase in towers produced at those facilities, while cost of goods sold increased by only $6.8 million at those locations as a result of productivity improvements, cost controls and the implementation of quality control measures that eliminated the need for outsourced quality assurance staffing. Revenues and cost of goods sold at DMI’s Canadian plant were down $9.1 million and $10.8 million, respectively, as a result of the idling of plant in the fourth quarter of 2011 due to a reduction in tower orders. DMI’s operating expenses decreased $0.6 million at its idled Canadian plant. At DMI’s other locations, operating expenses decreased $0.3 million as a result of lower salary and benefit expenses, due to staff reductions, and reduced maintenance expenses. As described above, DMI recorded a noncash asset impairment charge of $45.6 million in the second quarter of 2012 as a result of writing down its fixed assets to an indicated market value of $20.0 million. Depreciation expense decreased mainly as a result of the impairment of assets in Canada in 2011.

Manufacturing

(in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Operating Revenues	$ 63,581	$ 57,320	$ 6,261	10.9

Cost of Goods Sold	48,203	42,458	5,745	13.5
Operating Expenses	6,805	6,051	754	12.5
Depreciation and Amortization	3,219	3,232	(13)	(0.4)
Operating Income	$ 5,354	$ 5,579	$ (225)	(4.0)

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 $7.1 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 $0.8 million due to increased sales of industrial and medical packaging products.

Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment business, decreased $1.6 million, reflecting a $1.3 million decrease in commercial sales and a $0.3 million decrease 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 $6.3 million mainly as a result of increased sales volume.

Cost of goods sold at T.O. Plastics increased $0.6 million as a result of costs associated with the increase in sales of industrial and medical packaging products, offset by a $0.3 million decrease in costs related to improved productivity and efficiencies and more selective bidding practices.

Cost of goods sold at ShoreMaster decreased $0.8 million as a result of a $0.4 million decrease in costs related to the reduction in product sales combined with $0.4 million in productivity losses mainly related to 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 $0.7 million mainly due to increased benefit expenses related to employee incentives.

Operating expenses at T.O. Plastics were unchanged between the quarters.

Operating expenses at ShoreMaster increased $0.1 million between the quarters.

Construction

(in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Operating Revenues	$ 37,934	$ 49,133	$ (11,199)	(22.8)
Cost of Goods Sold	36,992	45,108	(8,116)	(18.0)
Operating Expenses	3,030	3,015	15	0.5
Depreciation and Amortization	470	495	(25)	(5.1)
Operating (Loss) Income	$ (2,558)	$ 515	$ (3,073)	(596.7)

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 $15.4 million due to a decrease in work volume and 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 $4.2 million as a result of an increase in electrical transmission, distribution and substation work facilitated by better weather and improved access to construction sites in the second quarter of 2012 compared with the second quarter of 2011.

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

Cost of goods sold at Foley Company decreased $11.0 million, mainly in material and subcontractor costs due to a decrease in work volume.

Cost of goods sold at Aevenia increased $2.9 million between the quarters as a result of the increase in electrical transmission, distribution and substation work completed in the second quarter of 2012.

Plastics

(in thousands)	Three Months Ended June 30, 2012	2011	Change	% Change
Operating Revenues	$ 41,490	$ 44,373	$ (2,883)	(6.5)
Cost of Goods Sold	31,257	36,220	(4,963)	(13.7)
Operating Expenses	2,328	1,436	892	62.1
Depreciation and Amortization	785	864	(79)	(9.1)
Operating Income	$ 7,120	$ 5,853	$ 1,267	21.6

Operating revenues for the Plastics segment decreased as result of a 12.3% decrease in pounds of polyvinyl chloride (PVC) pipe sold, partially offset by a 6.6% increase in the price per pound of pipe sold. The decrease in costs of goods sold was related to the decrease in pounds of pipe sold in combination with a 1.6% decrease in the cost per pound of PVC pipe sold between the quarters. The increase in operating expenses in the Plastics segment is mainly due to increased benefit expenses for employee incentives related to improved operating results.

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 June 30, 2012	2011	Change	% Change
Operating Expenses	$ 2,864	$ 3,423	$ (559)	(16.3)
Depreciation and Amortization	124	143	(19)	(13.2)

The decrease in corporate operating expenses reflects reductions in salary and benefit costs and expenditure for external services, insurance and public relations between the quarters.

Interest Charges

Interest charges decreased $0.7 million in the second quarter of 2012 compared with the second quarter of 2011, mainly as a result of a $65.9 million decrease in the average daily balance of short-term debt outstanding between the quarters.

Income Taxes – Continuing Operations

Income tax benefit - continuing operations increased $14.4 million in the three months ended June 30, 2012 compared with the three months ended June 30, 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 June 30, 2012 and 2011:

	Three Months Ended June 30,	
(in thousands)	2012	2011
(Loss) Income Before Income Taxes – Continuing Operations	$ (31,379)	$ 5,040
Add Back Canadian Losses not Subject to Income Tax Benefits	917	3,283
(Loss) Income Before Income Taxes – Continuing Operations, Subject to Taxes	(30,462)	8,323
Income Tax (Benefit) Expense Computed at the Company's Net Composite Federal and State Statutory Rate (39%)	(11,880)	3,246
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,831)	(1,929)
Corporate Owned Life Insurance	(13)	(178)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(149)	(265)
Medicare Part D Subsidy	(194)	(169)
Employee Stock Ownership Plan Dividend Deduction	(191)	(190)
Investment Tax Credit	(180)	(214)
Other Items - Net	(55)	(386)
Income Tax (Benefit) – Continuing Operations	$ (14,493)	$ (85)
Effective Income Tax Rate – Continuing Operations	46.2 %	(1.7)%

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 the second quarter of 2011, we sold Idaho Pacific Holdings, Inc. (IPH), our food ingredient processing company, and in the fourth quarter of 2011 we sold 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 months ended June 30, 2012 and 2011:

	For the Three Months Ended June 30,	
(in thousands)	2012	2011
Operating Revenues	$ --	$ 41,282
Operating Expenses	26	41,799
Operating Loss	(26)	(517)
Interest Charges	--	11

Other Income	--	1,259
Income Tax (Benefit) Expense	(11)	280
Net (Loss) Income from Operations	(15)	451
(Loss) Gain on Disposition Before Taxes	(490)	16,767
Income Tax (Benefit) Expense on Disposition	(35)	3,515
Net (Loss) Gain on Disposition	(455)	13,252
Net (Loss) Income	$ (470)	$ 13,703

Comparison of the Six Months Ended June 30, 2012 and 2011

Consolidated operating revenues were $561.3 million for the six months ended June 30, 2012 compared with $532.4 million for the six months ended June 30, 2011. Operating loss was $6.2 million for the six months ended June 30, 2012 compared with operating income of $29.0 million for the six months ended June 30, 2011. The Company recorded diluted earnings per share from continuing operations of ($0.22) for the six months ended June 30, 2012 compared to $0.28 for the six months ended June 30, 2011 and total diluted earnings per share of ($0.29) for the six months ended June 30, 2012 compared to $0.66 for the six months ended June 30, 2011.

Asset Impairment Charge—The DMI second quarter 2011 asset impairment described above resulted in a $45.6 million noncash asset impairment charge ($27.5 million, net-of-tax benefits), or $0.76 per share, in the six month period ended June 30, 2012.

Intersegment Eliminations—Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six month periods ended June 30, 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)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating Revenues:		
Electric	$ 119	$ 123
Nonelectric	1,760	1,251
Cost of Goods Sold	1,775	1,100
Other Nonelectric Expenses	104	274

Electric

(in thousands)	Six Months Ended June 30, 2012	2011	Change	% Change
Retail Sales Revenue	$ 150,141	$ 150,605	$ (464)	(0.3)
Wholesale Revenue – Company Generation	4,107	6,299	(2,192)	(34.8)
Net Revenue – Energy Trading Activity	973	978	(5)	(0.5)
Other Revenue	13,745	11,745	2,000	17.0
Total Operating Revenues	$ 168,966	$ 169,627	$ (661)	(0.4)
Production Fuel	27,879	36,657	(8,778)	(23.9)
Purchased Power – System Use	26,486	20,271	6,215	30.7
Other Operation and Maintenance Expenses	62,420	57,395	5,025	8.8
Asset Impairment Charge	432	--	432	--
Depreciation and Amortization	20,847	20,059	788	3.9
Property Taxes	5,287	4,826	461	9.6
Operating Income	$ 25,615	$ 30,419	$ (4,804)	(15.8)

Electric kwh Sales (in thousands)	Six Months Ended June 30, 2012	2011	Change	% Change
Retail kwh Sales	2,112,134	2,257,650	(145,516)	(6.4)
	166,755	246,056	(79,301)	(32.2)

Wholesale kwh Sales – Company Generation				
Wholesale kwh Sales – Purchased Power Resold	65,032	92,733	(27,701)	(29.9)

The $0.5 million decrease in retail sales revenue reflects the following:

a $5.7 million decrease in revenue, mainly due to a 6.4% reduction in retail kwh sales resulting from significantly milder weather in the first half of 2012 as heating degree days were down 27.8% compared with the first half of 2011,

- a $2.1 million decrease in revenue related to the recovery of fuel and purchased power costs, and
- a $1.5 million reduction in accrued conservation program cost recovery revenue related to the timing of the recognition of conservation costs and incentives recovered through the Minnesota Conservation Improvement Program surcharge,

offset by:

- a $4.9 million increase in revenue related to rate design changes implemented in Minnesota in October 2011 on finalization of OTP's 2010 general rate case,
- a $2.1 million increase in transmission costs recovery rider revenue as a result of increased investment in transmission assets, and
- a $1.8 million revenue reduction in the first half of 2011 related to accruing a refund for a portion of revenues collected under interim rates in 2010 during OTP's most recent Minnesota rate case.

Wholesale electric revenue from company-owned generation decreased $2.2 million as a result of a 32.2% decrease in wholesale kwh sales. Lower wholesale demand due to milder weather drove wholesale prices down, reducing opportunities to sell competitively in wholesale markets. Additionally, OTP's plant availability was reduced in the second quarter of 2012 as Coyote Station, OTP's lowest fuel-cost plant, was shut down for seven weeks of scheduled maintenance and Big Stone Plant had a 10-day spring maintenance outage, resulting in a 28.9% reduction in kwhs generated from OTP's steam-powered and combustion turbine generators between the periods.

Other electric operating revenue increased $2.0 million as a result of:

- a $3.9 million increase in transmission tariff revenues due, in part, to revenues from CapX2020 transmission project investments, and
- a 0.3 million increase in other miscellaneous services revenue,

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 $1.1 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 $8.8 million as a result of the 28.9% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 6.9% increase in the cost of fuel per kwh generated. Generation levels decreased in response to lower demand due to mild weather and because of scheduled plant maintenance outages. The cost of purchased power for retail sales increased $6.2 million as a result of a 57.4% increase in kwhs purchased, partially offset by a 17.0% decrease in the cost per kwh purchased. The increase in kwhs purchased was mainly due to the reduced availability of OTP's steam-powered generators.

Electric operating and maintenance expenses increased $5.0 million due to the following:

- a $2.0 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 $1.6 million increase in MISO transmission service charges, mainly Schedule 26 charges,
- a $1.1 million increase in maintenance expenses at Coyote Station related to its second quarter 2012 seven-week scheduled major maintenance shutdown,
- a $0.8 million increase in maintenance costs at Big Stone Plant,
- a $0.4 million increase in vegetation management expenses, and
- a $0.3 million increase in bad debt expense related to a reduction in the allowance for uncollectible accounts in the first quarter of 2011, resulting in a decrease in bad debt expense in that period,

offset by:

- a $1.2 million reduction in incurred conservation program costs, commensurate with a reduction in accrued revenues related to the future recovery of those 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 $0.8 million increase in Electric segment depreciation expense is related to 2011 property additions. The $0.5 million increase in property taxes is due to higher taxes on electric distribution property along with increased investments in transmission and distribution property.

Wind Energy

	Six Months Ended June 30,			
(in thousands)	2012	2011	Change	% Change
Revenues	$ 114,720	$ 102,013	$ 12,707	12.5
Cost of Goods Sold	99,574	103,896	(4,322)	(4.2)
Operating Expenses	3,787	5,594	(1,807)	(32.3)
Asset Impairment Charge	45,573	--	45,573	--
Depreciation and Amortization	4,155	5,310	(1,155)	(21.8)
Operating Loss	$ (38,369)	$ (12,787)	$ (25,582)	(200.1)

Revenues at DMI's U.S. plants increased $33.1 million due to a 13.9% increase in towers produced at those facilities, while cost of goods sold increased by only $19.7 million at those locations as a result of productivity improvements, cost controls and the implementation of quality control measures that eliminated the need for outsourced quality assurance staffing. Revenues and cost of goods sold at DMI's Canadian plant were down $20.4 million and $24.0 million, respectively, as a result of the idling of plant in the fourth quarter of 2011 due to a reduction in tower orders. DMI's operating expenses decreased $1.2 million at its idled Canadian plant. At DMI's other locations, operating expenses decreased $0.6 million as a result of lower salary and benefit expenses, due to staff reductions, and reduced maintenance and travel expenses. As described above, DMI recorded a noncash asset impairment charge of $45.6 million in the second quarter of 2012 as a result of writing down its fixed assets to an indicated market value of $20.0 million. Depreciation expense decreased mainly as a result of the impairment of assets in Canada in 2011.

Manufacturing

	Six Months Ended June 30,			
(in thousands)	2012	2011	Change	% Change
Operating Revenues	$ 129,575	$ 112,681	$ 16,894	15.0
Cost of Goods Sold	98,914	84,447	14,467	17.1
Operating Expenses	13,891	10,599	3,292	31.1
Depreciation and Amortization	6,415	6,402	13	0.2
Operating Income	$ 10,355	$ 11,233	$ (878)	(7.8)

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

Revenues at BTD increased $19.0 million as a result of higher sales volume due to improved customer demand.

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

Revenues at ShoreMaster decreased $3.4 million, reflecting a $3.8 million decrease in commercial sales, partially offset by a $0.4 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 $15.4 million as a result of increased sales volume.

Cost of goods sold at T.O. Plastics increased $0.9 million as a result of costs associated with the increase in sales of industrial and medical packaging products, offset by a $0.5 million decrease in costs related to improved productivity and efficiencies.

Cost of goods sold at ShoreMaster decreased $1.4 million as a result of a $2.2 million decrease in costs related to the reduction in product sales, offset by $0.8 million in severance and relocation costs incurred in 2012 related to shutting down ShoreMaster's commercial production operations in Camdenton, Missouri and moving parts and equipment 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 $2.0 million mainly due to increased benefit expenses related to employee incentives, but also due to increased salary and benefit expenses related to workforce expansion and increases in expenditures for contracted services, insurance and advertising.

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

Operating expenses at ShoreMaster increased $1.4 million, reflecting a $0.5 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

	Six Months Ended June 30,			
(in thousands)	2012	2011	Change	% Change
Operating Revenues	$ 73,551	$ 86,648	$ (13,097)	(15.1)
Cost of Goods Sold	75,685	79,397	(3,712)	(4.7)
Operating Expenses	6,310	6,121	189	3.1
Depreciation and Amortization	904	940	(36)	(3.8)
Operating (Loss) Income	$ (9,348)	$ 190	$ (9,538)	--

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

Revenues at Foley Company decreased $22.5 million, due to a decrease in work volume and the effect of cost overruns on estimated revenues recognized under percentage-of-completion accounting.

Revenues at Aevenia increased $9.4 million between the periods as a result an increase in electrical transmission, distribution and substation work facilitated by better weather and improved access to construction sites in the first half of 2012 compared with the first half of 2011.

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

Cost of goods sold at Foley Company decreased $11.3 million, mainly in material and subcontractor costs due to a decrease in work volume between periods.

Cost of goods sold at Aevenia increased $7.6 million between the periods as a result of the increase in electrical transmission, distribution and substation work performed in the first half of 2012.

The increase in operating expenses in our Construction segment mainly reflects increases in outside service expenses at Foley.

Plastics

(in thousands)	Six Months Ended June 30, 2012	2011	Change	% Change
Operating Revenues	$ 76,365	$ 62,851	$ 13,514	21.5
Cost of Goods Sold	58,204	52,940	5,264	9.9
Operating Expenses	3,691	2,657	1,034	38.9
Depreciation and Amortization	1,598	1,667	(69)	(4.1)
Operating Income	$ 12,872	$ 5,587	$ 7,285	130.4

Operating revenues for the Plastics segment increased as result of a 10.9% increase in pounds of PVC pipe sold combined with a 9.6% 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 slightly offset by a 0.9% decrease in the cost per pound of PVC pipe sold. The increase in operating expenses in the Plastics segment is mainly due to increased benefit expenses for employee incentives related to improved operating results, but also reflects increases in salaries and 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)	Six Months Ended June 30, 2012	2011	Change	% Change
Operating Expenses	$ 7,105	$ 5,393	$ 1,712	31.7
Depreciation and Amortization	252	280	(28)	(10.0)

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 $1.5 million in the first six months of 2012 compared with the first six months of 2011, mainly as a result of an $80.6 million decrease in the average daily balance of short-term debt outstanding between the periods.

Other Income

The increase in other income of $0.6 million in the six months ended June 30, 2012 compared with the six months ended June 30, 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 $0.1 million increase in the cash surrender value of corporate-owned life insurance policies.

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Income Taxes – Continuing Operations

Income taxes - continuing operations decreased $15.3 million in the six months ended June 30, 2012 compared with the six months ended June 30, 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 six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,	
(in thousands)	2012	2011
(Loss) Income Before Income Taxes – Continuing Operations	$(21,591)	$11,491
Add Back Canadian Losses not Subject to Income Tax Benefits	1,368	6,780
(Loss) Income Before Income Taxes – Continuing Operations, Subject to Taxes	(20,223)	18,271
Income Tax (Benefit) Expense Computed at the Company's Net Composite Federal and State Statutory Rate (39%)	(7,887)	7,126
Increases (Decreases) in Tax from:		
Federal PTCs	(3,818)	(3,905)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	(676)	--
Corporate Owned Life Insurance	(385)	(266)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(371)	(555)
Medicare Part D Subsidy	(391)	(361)
Employee Stock Ownership Plan Dividend Deduction	(381)	(384)
Canadian Revenue Authority Audit Settlement	--	156
Investment Tax Credit	(360)	(427)
Other Items - Net	73	(231)
Income Tax (Benefit) Expense – Continuing Operations	$(14,196)	$1,153
Effective Income Tax Rate – Continuing Operations	65.7 %	10.0 %

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 the second quarter of 2011, we sold IPH, our food ingredient processing company, and in the fourth quarter of 2011 we sold Wylie, our trucking business. On January 18, 2012 ShoreMaster completed the sale of the assets of its wholly owned subsidiary, Aviva, and on February 29, 2012 we completed the sale of 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 six months ended June 30, 2012 and 2011:

	For the Six Months Ended June 30,	
(in thousands)	2012	2011
Operating Revenues	$ 16,352	$ 99,460
Operating Expenses	14,928	99,343
Operating Income	1,424	117

Interest Charges	147	31
Other Income	122	1,416
Income Tax Expense	573	568
Net Income from Operations	826	934
(Loss) Gain on Disposition Before Taxes	(3,713)	16,767
Income Tax (Benefit) Expense on Disposition	(169)	3,515
Net (Loss) Gain on Disposition	(3,544)	13,252
Net (Loss) Income	$ (2,718)	$ 14,186

FINANCIAL POSITION

The following table presents the status of our lines of credit as of June 30, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on June 30, 2012	Restricted due to Outstanding Letters of Credit	Available on June 30, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$200,000	$ 2,289	$ 850	$ 196,861	$ 198,776
OTP Credit Agreement	170,000	8,985	3,050	157,965	165,950
Total	$370,000	$ 11,274	$ 3,900	$ 354,826	$ 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, 2012 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. On May 14, 2012 we entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. Equity or debt financing will be required in the period 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 $32.1 million were sold in the first four months of 2012. 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.

Cash provided by operating activities from continuing operations was $44.1 million for the six months ended June 30, 2012 compared with $29.1 million for the six months ended June 30, 2011. The $15.0 million increase in cash provided by operating activities from continuing operations reflects a decrease in net income of $34.6 million, offset by $46.0 million in noncash asset impairment charges and a $5.0 million reduction in cash used for working capital items between the periods.

Net cash used in investing activities of continuing operations was $64.2 million for the six months ended June 30, 2012 compared to $37.6 million for the six months ended June 30, 2011. An increase in cash used for capital expenditures at the electric utility of $32.5 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 $2.9 million. Net proceeds from the sale of discontinued operations of $24.3 million in the first half of 2012, which were used to pay down short-term borrowings and for other corporate purposes, reflect proceeds, net of selling costs, of $24.0 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 half of 2012 reflects cash used by DMS to purchase assets held under operating leases. Net cash used in investing activities of discontinued operations of $13.5 million in the first half of 2011 mainly reflects cash used by DMS to purchase assets held under operating leases.

Net cash used in financing activities from continuing operations decreased $66.8 million in the six months ended June 30, 2012 compared with the six months ended June 30, 2011 mainly due to a $70.0 million net increase in short-term borrowings and checks issued in excess of cash between the periods. We also issued $2.0 million in long-term debt and paid $0.7 million in short-term and long-term debt issuance expenses in the first six months of 2011. ShoreMaster paid $2.8 million to buy out a capital lease in the second quarter of 2012.

Our contractual obligations under other purchase obligations reported in the table on page 54 of our Annual Report on Form 10-K for the year ended December 31, 2011 have increased by $18.7 million for 2012, $26.1 million for 2013 and 2014, and $19.5 million for 2015 and 2016, for contracts related to the construction of CapX2020 transmission projects, a new air quality control system at Big Stone Plant in South Dakota, and a water handling project at Coyote Station in North Dakota.

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.

In April 2012, ShoreMaster exercised a purchase option on a building it had been leasing under a capital lease and paid off the remaining $2.8 million balance of its lease obligation.

On July 13, 2012 we prepaid in full our outstanding $50 million, 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note) issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between us and Cascade Investment, L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by us to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. We used funds available under the Credit Agreement for the prepayment. This early retirement reflects our desire to lower our long-term debt outstanding given our recent recent divestitures and our anticipated divestiture of DMI. This retirement of debt strengthens our consolidated capital structure and will positively affect future years' earnings by lowering interest costs. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 prepayment premium, which will reduce diluted earnings per share by $0.22 in 2012. The $50,000,000 of debt retired on July 13, 2012 was included in current maturities of long-term debt on our June 30, 2012 consolidated balance sheet. Cascade owned approximately 9.6% of our outstanding common stock as of December 31, 2011.

The following table presents the status of the corporation's lines of credit as of July 31, 2012 and June 30, 2012:

(in thousands)	Line Limit	In Use On July 31, 2012	Restricted due to Outstanding Letters of Credit	Available on July 31, 2012	Available on June 30, 2012
Otter Tail Corporation Credit Agreement	$200,000	$ 60,000	$ 733	$ 139,267	$ 196,861
OTP Credit Agreement	170,000	9,124	3,050	157,826	157,965
Total	$370,000	$ 69,124	$ 3,783	$ 297,093	$ 354,826

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 our 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 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. 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 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.

Financial Covenants
As of June 30, 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 June 30, 2012 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 2.06 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 June 30, 2012 OTP’s Interest and Dividend Coverage Ratio calculated under the requirements of the OTP Credit Agreement was 3.22 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 June 30, 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 3.22 to 1.00.

As of June 30, 2012 our interest-bearing debt to total capitalization was 0.47 to 1.00 on a fully consolidated basis and 0.50 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

As of June 30, 2012, we and our subsidiary companies have outstanding letters of credit totaling $10.8 million, but our line of credit borrowing limits are only restricted by $3.9 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 and the anticipated classification of DMI under discontinued operations, we are updating our 2012 expectations for diluted earnings per share from continuing operations to a range of $0.84 to $1.09 (inclusive of an after tax charge of $0.22 per share for early retirement of long term debt in the third quarter of 2012) from our previously announced range of $1.05 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:

Previous 2012 Earnings Per Share Guidance Range	Low	High
Electric	$1.00	$1.05
Wind Energy	($0.10)	$0.00
Manufacturing	$0.36	$0.41
Construction	($0.13)	($0.08)
Plastics	$0.18	$0.23
Corporate	($0.26)	($0.21)
Total – Continuing Operations	$1.05	$1.40
Discontinued Operations:		
Net Earnings	$0.00	$0.03
Loss on Sale of Disc. Ops.	($0.10)	($0.08)
Total	$0.95	$1.35

Updated 2012 Earnings Per Share Guidance Range	Low	High
Electric	$1.00	$1.05
Wind Energy	$0.00	$0.00
Manufacturing	$0.25	$0.30
Construction	($0.18)	($0.13)
Plastics	$0.24	$0.29
Corporate –Recurring Costs	($0.25)	($0.20)
Subtotal	$1.06	$1.31
Corporate – Debt Extinguishment	($0.22)	($0.22)
Total – Continuing Operations	$0.84	$1.09
Discontinued Operations:		
Net Loss	($0.09)	($0.04)
DMI Asset Impairment Charge	($0.81)	($0.76)
Loss on Sale of Discontinued Operations	($0.10)	($0.08)
Total	($0.16)	$0.21

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

We expect net income in our Electric segment to be in the same range as previous guidance.

We expect to complete a sale of our Wind Energy segment assets by early 2013 and, therefore, we expect DMI's 2012 results to be included in discontinued operations. 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 is expected to continue to generate revenues, earnings and cash flows for the remainder of 2012 but DMI's second quarter 2012 noncash asset impairment charge will have a negative impact on consolidated results in 2012. Backlog in the Wind Energy segment is $70 million for the remainder of 2012.

We now expect 2012 earnings from our Manufacturing segment to be lower than previous guidance primarily due to lower earnings at ShoreMaster and BTD. Continued reductions in commercial revenues at ShoreMaster along with higher than expected commercial operating expenses are the primary reason for the revised outlook. BTD expects lower earnings compared to previous guidance due to reduction in sales volume at its Illinois plant and lower scrap prices for steel in the second half of 2012 compared with the first half of 2012. Backlog in place for the manufacturing companies is $76 million for 2012 compared with $62 million one year ago.

We now expect a larger net loss from our Construction segment in 2012 as Foley continued to experience cost overruns on certain major projects in the first half of 2012. Backlog in place for the construction businesses is $73 million for 2012 compared with $84 million one year ago.

We are increasing the earning guidance for our Plastics segment net income in 2012, compared with previous guidance, based on the strength of its performance in the first half of 2012 and current market conditions.

We expect corporate general and administrative costs 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 June 30, 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 ex 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. The sale of any of our businesses also exposes us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

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’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 (CO2) emissions, could affect OTP’s operating costs and the costs of supplying electricity to its customers.

The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact the value of DMI’s fixed assets and result in an additional impairment of these assets if we are unable to agree to terms related to the June 2012 nonbinding letter of interest to sell these assets. 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.

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 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 June 30, 2012 we had exposure to market risk associated with interest rates because we had $2.3 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 $9.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.5% under OTP's $170 million revolving credit facility. At June 30, 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 June 30, 2012 OTP had recognized, on a pretax basis, $131,000 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 June 30, 2012, are 100% offset by forward energy sales contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of $131,000.

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 June 30, 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 June 30, 2012 and December 31, 2011, and the change in our consolidated balance sheet position from December 31, 2011 to June 30, 2012 and December 31, 2010 to June 30, 2011:

(in thousands)	June 30, 2012	December 31, 2011
Other Current Asset – Derivative Asset	$ 2,402	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	6,952	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	11,175	10,749
Total Assets	20,529	19,760
Derivative Liability	(20,337)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(61)	(96)
Total Liabilities	(20,398)	(18,866)
Fair Value Adjustments Included in Earnings	$ 131	$ 894

(in thousands)	Year-to-Date June 30, 2012	Year-to-Date June 30, 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	(700)	(151)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	161	526
Changes in Fair Value of Contracts Entered into in Current Period	(30)	120
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 131	$ 646

The recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2012 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	3rd Qtr 2012	4th Qtr 2012	1st Qtr 2013	Total
Net Gain	$ 5	$ 123	$ 3	$ 131

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 June 30,		Six Months Ended June 30,	
(in thousands)	2012	2011	2012	2011
Net Gains (Losses) on Forward Electric Energy Contracts	$ (50)	$ 139	$ 144	$ 131

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 June 30, 2012 was $348,000. As of June 30, 2012 OTP had a net credit risk exposure of $860,000 from eight counterparties with investment grade credit ratings. OTP had no exposure at June 30, 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 $860,000 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 June 30, 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 June 30, 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 June 30, 2012.

During the fiscal quarter ended June 30, 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

We are updating the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 30 through 37 of our Annual Report on Form 10-K for the year ended December 31, 2011, related to divestitures and in light of the nonbinding letter of interest we entered into in June of 2012 to sell the assets of DMI Industries, Inc.

The following general risk factor from our 2011 Annual Report on Form 10-K has been revised.

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

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

Revised Risk Factor:

We may, from time to time, sell one or more of our nonelectric businesses to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any business sold. The sale of any of our businesses also exposes us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

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

The following Wind Energy segment risk factor from the Company's 2011 Annual Report on Form 10-K has been revised.

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

Our wind tower manufacturing business is focused on supplying towers to wind turbine manufacturers and owners and operators of wind energy generation facilities. The wind industry is dependent on federal tax incentives and state renewable portfolio standards and may not be economically viable absent such incentives.

The federal government provides economic incentives to the owners of wind energy facilities, including a federal production tax credit, an investment tax credit and a cash grant equal in value to the investment tax credit. These programs provide material incentives to develop wind energy generation facilities and thereby impact the demand for our manufactured products and services. The failure of Congress to extend or renew these incentives beyond their current expiration dates could significantly delay the development of wind energy generation facilities and the demand for wind turbines, towers, gearing and related components. We cannot assure that any extension or renewal of the production tax credit, investment tax credit or cash grant program will be enacted prior to its expiration or, if allowed to expire, that any extension or renewal enacted thereafter would be enacted with retroactive effect. Any delay or failure to extend or renew the federal production tax credit, investment tax credit or cash grant program in the future could have a material adverse impact on our business, results of operations and future financial performance.

State renewable energy portfolio standards generally require or encourage state-regulated electric utilities to supply a certain proportion of electricity from renewable energy sources or devote a certain portion of their plant capacity to renewable energy generation. Currently, the majority of states and the District of Columbia have renewable energy portfolio standards in place and certain other states have voluntary utility commitments to supply a specific percentage of their electricity from renewable sources. Any changes to existing renewable energy portfolio standards, the enactment of renewable energy portfolio standards in additional states, or the enactment of a federal renewable energy portfolio may impact the demand for our products. We cannot assure you that government support for renewable energy will continue. The elimination of, or reduction in, state or federal government policies that support renewable energy could have a material adverse impact on our business, results of operations and future financial performance.

Revised Risk Factor:

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 the value of DMI's fixed assets and result in an additional impairment of these assets if we are unable to agree to terms related to the June 2012 nonbinding letter of interest to sell these assets. The Federal Production Tax Credit is currently scheduled to expire on December 31, 2012.

The following Wind Energy segment risk factor from the Company's 2011 Annual Report on Form 10-K has been eliminated.

Competition from foreign and domestic manufacturers, cost management in a fixed price contract project environment, fluctuations in foreign currency exchange rates and general economic conditions could affect the revenues and earnings of our Wind Energy segment.

Our Wind Energy segment is subject to risks associated with competition from foreign and domestic manufacturers, some of whom have greater distribution capabilities, greater capital resources and other capabilities that may place downward pressure on margins and profitability. Our wind tower manufacturer operates in a fixed price project environment where balancing workload to costs can create variation in margins that may not be recoverable from customers. If DMI is not able to recover cost increases from its customers, it could have a negative effect on profit margins and income from our Wind Energy segment.

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 2011, we idled our 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.

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

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for incentive awards under the Company's 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2012	5,072	$ 21.79
May 2012	--	--

June 2012	--	--
Total	5,072	

54

Item 6. Exhibits

10.1	1999 Employee Stock Purchase Plan, As Amended (2012) (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Otter Tail Corporation on April 19, 2012).
10.2	Form of 2012 Restricted Stock Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.2 to the Form 8-K filed by Otter Tail Corporation on April 19, 2012).
10.3	Form of 2012 Performance Award Agreement (incorporated by reference to Exhibit 10.3 to the Form 8-K filed by Otter Tail Corporation on April 19, 2012).
10.4	Form of 2012 Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.4 to the Form 8-K filed by Otter Tail Corporation on April 19, 2012).
10.5	Distribution Agreement Dated May 14, 2012 between Otter Tail Corporation and J.P. Morgan Securities LLC (incorporated by reference to Exhibit 1.1 to the Form 8-K filed by Otter Tail Corporation on May 14, 2012).
10.6	Otter Tail Corporation Executive Restoration Plus Plan.
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: August 9, 2012

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