Otter Tail Corp
Form 10-Q
May 10, 2013

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 March 31, 2013

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:

April 30, 2013 – 36,268,494 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	March 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$37,532	$ 52,362
Accounts Receivable:		
Trade—Net	102,259	91,170
Other	10,018	7,684
Inventories	73,398	69,336
Deferred Income Taxes	19,306	30,964
Unbilled Revenues	14,836	15,701
Costs and Estimated Earnings in Excess of Billings	3,588	3,663
Regulatory Assets	21,326	25,499
Other	14,085	8,161
Assets of Discontinued Operations	4,585	19,092
Total Current Assets	300,933	323,632
Investments	9,417	9,471
Other Assets	26,783	26,222
Goodwill	38,971	38,971
Other Intangibles—Net	14,060	14,305
Deferred Debits		
Unamortized Debt Expense	4,638	5,529
Regulatory Assets	129,049	134,755
Total Deferred Debits	133,687	140,284
Plant		
Electric Plant in Service	1,429,549	1,423,303
Nonelectric Operations	187,646	186,094
Construction Work in Progress	88,848	77,890
Total Gross Plant	1,706,043	1,687,287
Less Accumulated Depreciation and Amortization	648,150	637,835
Net Plant	1,057,893	1,049,452
Total Assets	$1,581,744	$ 1,602,337

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	March 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$1,335	$--
Current Maturities of Long-Term Debt	179	176
Accounts Payable	87,240	88,406
Accrued Salaries and Wages	11,627	20,571
Billings In Excess Of Costs and Estimated Earnings	19,132	16,204
Accrued Taxes	12,726	12,047
Derivative Liabilities	14,009	18,234
Other Accrued Liabilities	7,160	6,334
Liabilities of Discontinued Operations	5,551	11,156
Total Current Liabilities	158,959	173,128
Pensions Benefit Liability	107,440	116,541
Other Postretirement Benefits Liability	59,508	58,883
Other Noncurrent Liabilities	23,464	22,244
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	166,460	171,787
Deferred Tax Credits	30,817	31,299
Regulatory Liabilities	69,575	68,835
Other	477	466
Total Deferred Credits	267,329	272,387
Capitalization		
Long-Term Debt, Net of Current Maturities	437,399	421,680
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2013 – None; 2012 – 155,000 Shares	--	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, 2013—36,212,693 Shares; 2012—36,168,368 Shares	181,063	180,842
Premium on Common Shares	254,589	253,296

Retained Earnings	96,310	92,221
Accumulated Other Comprehensive Loss	(4,317)	(4,385)
Total Common Equity	527,645	521,974
Total Capitalization	965,044	959,154
Total Liabilities and Equity	$1,581,744	$1,602,337

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 March 31, 2013	2012
Operating Revenues		
Electric	$100,976	$89,968
Nonelectric	116,978	129,922
Total Operating Revenues	217,954	219,890
Operating Expenses		
Production Fuel - Electric	17,953	15,424
Purchased Power - Electric System Use	16,639	14,158
Electric Operation and Maintenance Expenses	32,447	30,013
Asset Impairment Charge - Electric	--	432
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	92,062	110,296
Other Nonelectric Expenses	13,778	13,902
Depreciation and Amortization	14,920	14,793
Property Taxes - Electric	2,916	2,617
Total Operating Expenses	190,715	201,635
Operating Income	27,239	18,255
Interest Charges	6,980	8,594
Other Income	861	982
Income from Continuing Operations Before Income Taxes	21,120	10,643
Income Taxes – Continuing Operations	5,886	468
Net Income from Continuing Operations	15,234	10,175
Discontinued Operations		
(Loss) Income - net of Income Tax (Benefit) Expense of ($205) and $413 for the respective periods	(81)	157
Gain (Loss) on Disposition - net of Income Tax Expense (Benefit) of $6 and ($134) for the respective periods	210	(3,089)
Net Gain (Loss) from Discontinued Operations	129	(2,932)
Net Income	15,363	7,243
Preferred Dividend Requirements and Other Adjustments	513	184
Earnings Available for Common Shares	$14,850	$7,059
Average Number of Common Shares Outstanding—Basic	36,075,131	35,995,179
Average Number of Common Shares Outstanding—Diluted	36,259,115	36,129,192
Basic Earnings (Loss) Per Common Share:		
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.41	$0.28
Discontinued Operations	--	(0.08)
	$0.41	$0.20
Diluted Earnings (Loss) Per Common Share:		
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.41	$0.28
Discontinued Operations	--	(0.08)
	$0.41	$0.20

Dividends Declared Per Common Share	$0.2975	$0.2975

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
(in thousands)	2013	2012
Net Income	$15,363	$7,243
Other Comprehensive (Loss) Income:		
Unrealized Gain on Available-for-Sale Securities:		
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(25)	--
(Losses) Gains Arising During Period	(5)	104
Income Tax Benefit (Expense)	11	(41)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(19)	63
Pension and Postretirement Benefit Plans:		
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 12)	145	102
Income Tax (Expense)	(58)	(41)
Pension and Postretirement Benefit Plans – net-of-tax	87	61
Total Other Comprehensive Income	68	124
Total Comprehensive Income	$15,431	$7,367

See accompanying notes to consolidated financial statements.

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

(in thousands)	Three Months Ended March 31, 2013	2012
Cash Flows from Operating Activities		
Net Income	$15,363	$7,243
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net (Gain) Loss from Sale of Discontinued Operations	(210)	3,089
Net Loss (Income) from Discontinued Operations	81	(157)
Depreciation and Amortization	14,920	14,793
Asset Impairment Charge	--	432
Deferred Tax Credits	(483)	(522)
Deferred Income Taxes	6,139	(7,717)
Change in Deferred Debits and Other Assets	4,800	7,872
Discretionary Contribution to Pension Plan	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	1,975	9,299
Allowance for Equity (Other) Funds Used During Construction	(293)	(162)
Change in Derivatives Net of Regulatory Deferral	378	281
Stock Compensation Expense—Equity Awards	392	287
Other—Net	25	1,855
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(13,423)	(14,897)
Change in Inventories	(4,062)	(5,029)
Change in Other Current Assets	(3,025)	(2,614)
Change in Payables and Other Current Liabilities	(3,440)	6,841
Change in Interest and Income Taxes Receivable/Payable	1,076	(1,884)
Net Cash Provided by Continuing Operations	10,213	9,010
Net Cash Used in Discontinued Operations	(2,400)	(1,159)
Net Cash Provided by Operating Activities	7,813	7,851
Cash Flows from Investing Activities		
Capital Expenditures	(23,327)	(35,511)
Net Proceeds from Disposal of Noncurrent Assets	729	1,234
Net Increase in Other Investments	(923)	(1,321)
Net Cash Used in Investing Activities - Continuing Operations	(23,521)	(35,598)
Net Proceeds from Sale of Discontinued Operations	10,465	24,362
Net Cash Used in Investing Activities - Discontinued Operations	(208)	(11,925)
Net Cash Used in Investing Activities	(13,264)	(23,161)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	--	10,546
Net Short-Term Borrowings	1,335	3,311
Proceeds from Issuance of Common Stock	1,156	--
Payments for Retirement of Preferred Stock	(15,500)	--
Proceeds from Issuance of Long-Term Debt	40,900	--
Short-Term and Long-Term Debt Issuance Expenses	(7)	(10)
Payments for Retirement of Long-Term Debt	(25,178)	(34)
Dividends Paid and Other Distributions	(11,307)	(11,037)
Net Cash (Used in) Provided by Financing Activities - Continuing Operations	(8,601)	2,776

Net Cash Used in Financing Activities - Discontinued Operations	--	(1,445)
Net Cash (Used in) Provided by Financing Activities	(8,601)	1,331
Net Change in Cash and Cash Equivalents - Discontinued Operations	(778)	(2,015)
Net Change in Cash and Cash Equivalents	(14,830)	(15,994)
Cash and Cash Equivalents at Beginning of Period	52,362	15,994
Cash and Cash Equivalents at End of Period	$37,532	$--

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the 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, 2012, 2011 and 2010 included in the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2012. Because of seasonal and other factors, the earnings for the three months ended March 31, 2013 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, 2012.

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 (FASB) 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.

The companies in the Construction segment 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 costs incurred to total estimated costs on construction projects. Following are the percentages of the Company’s consolidated revenues recorded under the percentage-of-completion method:

	Three Months Ended March 31,	
	2013	2012
Percentage-of-Completion Revenues	12.1%	16.2%

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

March 31,

(in thousands)	2013	December 31, 2012
Costs Incurred on Uncompleted Contracts	$302,324	$307,085
Less Billings to Date	(319,025)	(321,388)
Plus Estimated Earnings Recognized	1,157	1,762
	$(15,544)	$(12,541)

The following amounts are included in the Company’s consolidated balance sheets:

(in thousands)	March 31, 2013	December 31, 2012
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$3,588	$3,663
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(19,132)	(16,204)
	$(15,544)	$(12,541)

The Company has a standard quarterly Estimate at Completion process in which management reviews the progress and performance of the Company’s contracts accounted for under percentage-of-completion accounting. As part of this process, management reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include management’s judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. Management must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if management determines it will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if management determines it will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract’s percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of the Company’s contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

In 2012, Foley Company (Foley) experienced cost overruns in excess of estimated costs on several large projects. All of these projects were substantially completed as of December 31, 2012. Estimated costs on certain projects in excess of previous period estimates resulted in pretax charges of $6.5 million in the three months ended March 31, 2012, and $0.5 million, in the three months ended March 31, 2013.

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. The warranty reserve balance as of December 31, 2012 and March 31, 2013 relates entirely to products produced by DMI Industries, Inc. (DMI) and ShoreMaster, Inc. (ShoreMaster) and is included in liabilities of discontinued operations. See note 17 to consolidated financial statements.

Retainage

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

March 31,

(in thousands)	2013	December 31, 2012
Accounts Receivable Retained by Customers	$9,195	$12,227

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.

Fair values for OTP's forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table below as of March 31, 2013 and December 31, 2012, are based on prices indexed to observable prices at an active trading hub. The range for Level 3 forward electric inputs was $18.50 to $47.00 per megawatt-hour. The weighted average price was $37.50 per megawatt-hour.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the three-month periods ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(in thousands)	2013	2012
Forward Energy Contracts - Fair Values Beginning of Period	$(17,782)	$--
Transfers into Level 3 from Level 2	--	(15,884)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	2,195	1,439
Changes in Fair Value of Contracts Entered into in Prior Periods	3,320	(5,460)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(12,267)	(19,905)
Net Gain (Loss) Recognized as Regulatory Assets on contract entered into in Period	32	(13)
Forward Energy Contracts - Net Derivative Liability Fair Values End Period	$(12,235)	$(19,918)

In the table below, $274,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and $12,541,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of March 31, 2013 are related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of fuel costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on the Company's consolidated net income is $0 and the net income impact of any future fair valuation adjustments of these contracts will be $0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on the Company's reported consolidated net income for the three month periods ended March 31, 2013 and 2012.

The remaining $1,055,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and $1,023,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of March 31, 2013 are related to financial contracts that will not be settled by physical delivery of electricity but will be settled financially by the counterparty to the contract paying or receiving the difference between the contract price and the market price at the hour of scheduled delivery. Although the related forward energy purchase and sales contracts are 100% offsetting in terms of volumes and delivery periods, the purchase contracts and offsetting sales contracts do not have the same delivery points. Therefore, the net derivative gain related to these contracts of $32,000 as of March 31, 2013 is subject to change in subsequent reporting periods or on settlement. These contracts are scheduled for settlement in June, July and August of 2013. Any fluctuation in the factors used in the fair valuation of these contracts would not result in a significant change to the net fair value of the contracts.

The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2013 and December 31, 2012:

March 31, 2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$496	$1,329
Forward Gasoline Purchase Contracts		162	
Money Market Fund - Escrow Account Idaho Pacific Holdings, Inc. (IPH) Sale	1,500		
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	101		
Equity Securities - Nonqualified Retirement Savings Plan	9		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,644	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,300	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	177		
Equity Securities - Nonqualified Retirement Savings Plan	128		
Total Assets	$1,915	$9,602	$1,329
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$445	$13,564
Total Liabilities	$--	$445	$13,564

December 31, 2012 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$292	$210
Forward Gasoline Purchase Contracts		136	
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		7,620	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,305	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	357		
Equity Securities - Nonqualified Retirement Savings Plan	125		
Total Assets	$2,092	$9,353	$210
Liabilities:			

Derivative Liabilities - Forward Energy Contracts	$--	$242	$17,992
Total Liabilities	$--	$242	$17,992

Inventories
Inventories consist of the following:

(in thousands)	March 31, 2013	December 31, 2012
Finished Goods	$ 22,273	$ 21,893
Work in Process	8,489	8,800
Raw Material, Fuel and Supplies	42,636	38,643
Total Inventories	$ 73,398	$ 69,336

Goodwill and Other Intangible Assets
The following table summarizes changes to goodwill by business segment during 2013:

(in thousands)	Gross Balance December 31, 2012	Accumulated Impairments	Balance (net of impairments) December 31, 2012	Adjustments to Goodwill in 2013	Balance (net of impairments) March 31, 2013
Electric	$ --	$ --	$ --	$ --	$ --
Manufacturing	12,186	--	12,186	--	12,186
Construction	7,483	--	7,483	--	7,483
Plastics	19,302	--	19,302	--	19,302
Total	$ 38,971	$ --	$ 38,971	$ --	$ 38,971

Other Intangible Assets
The following table summarizes the components of the Company's intangible assets at March 31, 2013 and December 31, 2012:

March 31, 2013 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,298	$12,513	15 – 25 years
Other Intangible Assets Including Contracts	825	378	447	5 – 30 years
Total	$ 17,636	$ 4,676	$12,960	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$1,100	
December 31, 2012 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,085	$12,726	15 – 25 years
Other Intangible Assets Including Contracts	1,092	613	479	5 – 30 years
Total	$ 17,903	$ 4,698	$13,205	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$1,100	

The amortization expense for these intangible assets was:

(in thousands)	Three Months Ended March 31, 2013	2012
Amortization Expense – Intangible Assets	$ 244	$ 247

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

(in thousands)	2013	2014	2015	2016	2017
Estimated Amortization Expense – Intangible Assets	$977	$977	$977	$945	$849

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of March, 31 2013	2012
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions[1]	$ 8,901	$ 6,907

[1]Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.

Coyote Station Lignite Supply Agreement – Variable Interest Entity

In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining lignite coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, have the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE. Therefore, CCMC is not required to be consolidated in the Company’s consolidated financial statements.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the first delivery of coal to Coyote Station, scheduled for May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. OTP’s 35% share of development period costs, development fees and capital charges incurred by CCMC through March 31, 2013 and its maximum exposure to loss as a result of its involvement with CCMC as of March 31, 2013 totaled $9.0 million.

Reclassifications and Changes to Presentation

The Company’s consolidated income statement and consolidated statement of cash flows for the three months ended March 31, 2012 reflect the reclassifications of the operating results and cash flows of DMI and ShoreMaster to discontinued operations as a result of the completion of the sale of DMI’s assets and discontinuance of production activities in November 2012 and the sale of ShoreMaster on February 8, 2013. The reclassification had no impact on the Company’s total consolidated net income or cash flows for the three months ended March 31, 2012.

New Accounting Standards

Accounting Standards Update (ASU) 2011-11 and 2013-01

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities, which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity’s financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. In January 2013, the FASB issued ASU 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, to clarify which instruments and transactions are subject to the offsetting disclosure requirements established by ASU 2011-11. The amendments in ASU 2013-01 apply to derivatives accounted for in accordance with ASC 815 and clarify that only derivatives accounted for in accordance with ASC 815 are within the scope of the disclosure requirements. These disclosure requirements do not affect the presentation of amounts in the consolidated balance sheets. ASU 2013-01 is effective for fiscal years beginning on or after January 1, 2013, and interim periods within those annual periods. The Company implemented the disclosure guidance January 1, 2013. While, certain of the Company’s offsetting derivative asset and liability positions related to forward energy contracts with the same counterparty are subject to legally enforceable netting arrangements, the Company does not present its derivative assets and liabilities subject to legally enforceable netting arrangements, or any related payables or receivables, on a net basis on the face of its consolidated balance sheet. The Company has added disclosures and a table in note 5 to the consolidated financial statements indicating the amounts of its derivative forward energy contracts presented at fair value in accordance with ASC 815 that are subject to legally enforceable netting arrangements.

ASU 2013-02

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income, which requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under accounting principles generally accepted in the United States of America (U.S. GAAP) to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail on these amounts. This ASU is effective for reporting periods beginning after December 15, 2012. Additional information required by this update is included on the face of the Company’s consolidated statement of comprehensive income for the period ending March 31, 2013 and in note 12 to the consolidated financial statements.

2. Segment Information

The Company's businesses have been classified into four 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 four segments are: Electric, Manufacturing, Construction and Plastics.

The chart below indicates the companies included in each segment.

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.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of material and handling trays and horticultural containers. These businesses have manufacturing facilities in Illinois and Minnesota and sell products primarily in the United States.

Construction consists of businesses involved in 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.

No single customer accounted for over 10% of the Company's consolidated revenues in 2012. All of the Company's long-lived assets are within the United States.

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

	Three Months Ended March 31,			
	2013		2012	
United States of America	97.9	%	98.0	%
Mexico	1.2	%	0.9	%
Canada	0.9	%	1.1	%
All Other Countries (none greater than 0.05%)				

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three months ended March 31, 2013 and 2012 and total assets by business segment as of March 31, 2013 and December 31, 2012 are presented in the following tables:

Operating Revenue

	Three Months Ended March 31,	
(in thousands)	2013	2012
Electric	$ 101,010	$ 90,003
Manufacturing	53,166	59,434
Construction	26,425	35,617
Plastics	37,400	34,875
Corporate Revenues and Intersegment Eliminations	(47)	(39)
Total	$ 217,954	$ 219,890

Interest Expense

	Three Months Ended March 31,	
(in thousands)	2013	2012
Electric	$ 4,808	$ 4,851
Manufacturing	815	915
Construction	107	253
Plastics	248	346
Corporate and Intersegment Eliminations	1,002	2,229
Total	$ 6,980	$ 8,594

Income Taxes

	Three Months Ended March 31,	
(in thousands)	2013	2012
Electric	$ 4,082	$ 1,622
Manufacturing	2,218	2,324
Construction	(723)	(2,776)
Plastics	2,603	2,175
Corporate	(2,294)	(2,877)
Total	$ 5,886	$ 468

Earnings Available for Common Shares

	Three Months Ended March 31,	
(in thousands)	2013	2012
Electric	$ 11,931	$ 11,016
Manufacturing	3,318	3,465
Construction	(1,092)	(4,171)

Plastics		3,887		3,253
Corporate		(3,323)		(3,572)
Discontinued Operations		129		(2,932)
Total	$	14,850	$	7,059

Identifiable Assets

(in thousands)		March 31, 2013		December 31, 2012
Electric	$	1,222,994	$	1,226,145
Manufacturing		119,675		114,933
Construction		50,779		50,696
Plastics		88,230		78,855
Corporate		95,481		112,616
Discontinued Operations		4,585		19,092
Total	$	1,581,744	$	1,602,337

3. Rate and Regulatory Matters

Minnesota

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: 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the Minnesota Public Utilities Commission (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 recovery of Minnesota Renewable Resource Adjustment (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 $0.3 million for amounts eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of March 31, 2013. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. As the filing requesting to extend the period of the new rate for 18 months was still under review, a supplemental filing was submitted on February 15, 2013. This filing requested that the current rate be retained until a majority of the remaining costs are recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the request on April 4, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in our next general rate case.

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 exempt from the requirement to obtain a Minnesota CON. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case, unless a different return is determined to be in the public interest. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

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 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 MPUC 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. On March 26, 2012 the MPUC approved an all-in method for MISO regional cost allocations 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 for projects included in the TCR.

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. On August 22, 2012 the Minnesota Department of Commerce (MNDOC) filed comments and on August 24, 2012 the Minnesota Office of the Attorney General (MNOAG) filed comments. OTP filed reply comments on September 25, 2012 and supplemental comments on January 8, 2013 describing an agreement reached between OTP, the MNDOC and the MNOAG, to find eligible three of the twelve projects. On February 20, 2013 the MPUC approved the three projects as eligible for recovery. OTP filed its annual update to the TCR on February 7, 2013 to include the three new projects as well as updated costs associated with existing projects. OTP had a regulatory liability of $30,000 as of March 31, 2013 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

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.

The 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 Minnesota Conservation Improvement Program (MNCIP) through the use of an annual recovery mechanism approved by the MPUC.

A written order was issued by the MPUC on January 11, 2012 approving the recovery of $3.5 million for the 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for $2.6 million and recognized an additional $0.4 million of incentive related to 2011 in 2012. In December 2012, the MPUC approved the recovery of $2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kilowatt-hour (kwh) consumed. The written order was issued on December 10, 2012. On January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of the customer's bill to $0.00142 per kwh , which equates to approximately 1.9% of a customer's bill. OTP recognized $2.6 million of MNCIP financial incentives in 2012 relating to 2012 program results. On April 1, 2013 OTP submitted its annual 2012 financial incentive filing request for $2.7 million along with a request for an updated surcharge rate with a proposed implementation date of July 1, 2013.

OTP has a regulatory asset of $5.8 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of March 31, 2013. OTP recognized revenue for Minnesota conservation costs and incentives earned totaling $1.6 million in the three month period ended March 31, 2013, compared with $1.8 million in the three month period ended March 31, 2012.

North Dakota

Renewable Resource Cost Recovery Rider— On May 21, 2008 the North Dakota Public Service Commission (NDPSC) approved OTP's request for a North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed. In its 2009 annual request to the NDPSC to increase the amount of the NDRRA, OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. An NDRRA of $0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009. Terms of the approved settlement provide for the recovery of accrued costs and returns on investments in renewable energy facilities under the NDRRA over a period of 48 months beginning in January 2010.

The 2010 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, which was approved by the NDPSC on March 21, 2012. The 2011 NDRRA recovered $9.9 million over the period April 1, 2012 through March 31, 2013. OTP submitted its annual update to the NDRRA on December 28, 2012 with a proposed April 1, 2013 effective date. A notice of opportunity for hearing on the compliance filing was not timely issued by the NDPSC. Consequently, OTP was allowed to implement updated rates effective April 1, 2013. The NDPSC issued its notice of opportunity for hearing on March 28, 2013. An order retroactively approving the April 1, 2013 rates is expected in the second quarter of 2013. OTP has a regulatory asset of $0.7 million for amounts eligible for recovery through the NDRRA rider that had not been billed to North Dakota customers as of March 31, 2013.

Transmission Cost Recovery Rider—OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011, which was approved by the NDPSC on April 25, 2012 to go into effect May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider. In addition, OTP proposed to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved OTP's annual update on December 12, 2012 to go into effect January 1, 2013.

South Dakota

Transmission Cost Recovery Rider—OTP submitted a request for an initial South Dakota TCR rider to the South Dakota Public Utilities Commission (SDPUC) on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. OTP billed $570,000 to South Dakota customers under the TCR rider from December 1, 2011 through December 31, 2012. On September 4, 2012, OTP filed its annual update to the South Dakota TCR rider rate. Terms of a settlement with the SDPUC staff in OTP's South Dakota TCR filing were agreed to in April of 2013. Updated rates were approved on April 23, 2013 and went into effect on May 1, 2013. OTP had a regulatory liability of $82,000 as of March 31, 2013 for amounts billed to South Dakota customers that are subject to refund through the South Dakota TCR rider.

Federal

Wholesale power sales and transmission rates are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Federal Power Act of 1935, as amended. The FERC is an independent agency, which has 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 in OTP's formula rate: (1) 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 in which OTP is investing: the Fargo Project, the Bemidji Project and the 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 the 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 MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South – Brookings MVP and the Big Stone South – Ellendale MVP. Abandoned Plant recovery provides a basis for OTP to request recovery of prudently incurred costs in the event a project is cancelled for reasons beyond OTP's control.

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 petitioned the SDPUC on December 19, 2012 to certify a portion of the line route that was originally approved as part of the Big Stone II transmission development. The SDPUC approved the certification for the northern portion of the route on April 9, 2013. OTP and Xcel Energy expect to make a joint route permit filing in the second quarter of 2013 for the remaining portion of the project.

The Big Stone South – Ellendale 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. Applications for route permits are expected to be filed with the SDPUC and NDPSC 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.

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. Construction is underway for the remaining portions of the project, with completion scheduled for May 2015.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as a Multi-Value Project (MVP) under the MISO Tariff in December 2011. This project is anticipated to be completed in February 2015.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Recovery of OTP's CapX2020 transmission investments will be through the MISO Tariff and the Minnesota, North Dakota and South Dakota TCR riders.

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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 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 effective on May 29, 2012.

On January 14, 2011 OTP filed a petition asking the MPUC for ADP for anticipated costs associated with 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. Currently there is no rider mechanism available to recover environmental upgrades at out of state plants in Minnesota, so the Minnesota share of the investment in the AQCS and a return on the investment are expected to be recovered under general rates when the cost of the system is included in rate base.

OTP filed an application for an ADP with the NDPSC on May 20, 2011 for anticipated costs attributable to serving OTP's North Dakota customers. The NDPSC approved OTP's request on May 9, 2012.

On February 8, 2013, OTP filed a request with the NDPSC for an environmental rider to recover the revenue requirements plus carrying charges of the 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. The NDPSC suspended the rate without approval on March 1, 2013 pending review of the request. The review is expected to be completed by the end of May 2013.

On March 30, 2012 OTP requested approval from the SDPUC for an environmental rider to recover costs associated with the AQCS. This rider is designed to recover the revenue requirements plus carrying charges of the 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. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013.

Big Stone II Project

On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

Minnesota—OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers at that time was $3.2 million.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone II transmission facilities. The April 25, 2011 MPUC order instructed OTP to transfer the $3.2 million Minnesota share of Big Stone II transmission costs to CWIP and to create a tracker account through which any over or under recoveries could be accumulated for refund or recovery determination in future rate cases as a regulatory liability or asset. If determined eligible for recovery under the FERC-approved MISO regional transmission tariff, the Minnesota portion of Big Stone II transmission costs and accumulated Allowance for Funds Used During Construction (AFUDC) will receive rate base treatment and recovery through the FERC-approved MISO regional transmission rates. Any amounts over or under collected through MISO rates or from other sources will be reflected in the tracker account. The Minnesota Route Permit for these transmission facilities expired on March 17, 2013.

North Dakota—In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group Interveners. The terms of the settlement agreement indicate that OTP’s discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The North Dakota jurisdictional share of Big Stone II generation costs incurred by OTP and subject to recovery from North Dakota ratepayers was determined to be $4.1 million. The North Dakota portion of Big Stone II generation costs is being recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was $1.1 million. OTP transferred the North Dakota share of Big Stone II transmission costs to CWIP, with such costs subject to AFUDC continuing from September 2009. According to the settlement agreement approved for recovery of the Big Stone II generation costs, if construction of all or a portion of the transmission facilities commences within three years of the NDPSC order approving the settlement agreement, the North Dakota portion of Big Stone II transmission costs and accumulated AFUDC shall be included in the rate base investment for these future transmission facilities. If construction is not commenced on any of the transmission facilities within three years of the NDPSC order approving the settlement agreement, OTP may petition the NDPSC to either continue accounting for these costs as CWIP or to commence recovery of such costs. Approximately $0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. The remaining transmission costs have been determined not to be useable by other active transmission projects.

On March 29, 2013, OTP filed a request with the NDPSC for a six month extension of the Big Stone II Cost Recovery Rider. This extension would allow for the recovery of the remaining transmission related costs which have been determined to not be useable with other transmission projects. Pending review and approval by the NDPSC, OTP will keep the existing Big Stone II rates in place which would allow recovery of the remaining transmission costs plus accumulated AFUDC over a six month period starting with bills on and after August 1, 2013.

South Dakota—OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately $1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013, OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II Transmission costs until OTP’s next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013.

On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits from the original Big Stone II transmission owners to OTP. A petition was filed by OTP in September 2012 to certify that no substantial changes had occurred that would require a new permit. The SDPUC approved the certification of the Big Stone II transmission route permit for a portion of the Big Stone South - Brookings MVP transmission project on April 9, 2013.

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 regulatory assets reflect incurred costs eligible for recovery in future periods on which the Company will not earn a rate of return: Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits, the Accumulated ARO Accretion/Depreciation Adjustment, Debt Reacquisition Premiums, Big Stone II Unrecovered Project Costs – Minnesota, Deferred Income Taxes, the MISO Schedule 26/26A Transmission Cost Recovery Rider True-up, Big Stone II Unrecovered Project Costs – North Dakota, General Rate Case Recoverable Expenses and Deferred Holding Company Formation Costs. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following regulatory assets represent amounts eligible for recovery under alternative revenue programs or on which the Company earns an incentive or rate of return: Conservation Improvement Program Costs and Incentives, North Dakota Renewable Resource Rider Accrued Revenues, Minnesota Renewable Resource Rider Accrued Revenues, Big Stone II Unrecovered Project Costs – South Dakota, North Dakota Transmission Rider Accrued Revenues and South Dakota Transmission Rider Accrued Revenue The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

	March 31, 2013			Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$8,410	$107,437	$115,847	see note
Deferred Marked-to-Market Losses	6,109	6,469	12,578	69 months
Conservation Improvement Program Costs and Incentives	2,811	3,110	5,921	15 months
Accumulated ARO Accretion/Depreciation Adjustment	--	4,261	4,261	asset lives
Debt Reacquisition Premiums	351	2,504	2,855	234 months
Big Stone II Unrecovered Project Costs – Minnesota	533	1,482	2,015	42 months
Deferred Income Taxes	--	1,734	1,734	asset lives
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	--	1,352	1,352	see note
Big Stone II Unrecovered Project Costs – South Dakota	100	686	786	94 months
North Dakota Renewable Resource Rider Accrued Revenues	716	--	716	12 months
Deferred Environmental Compliance Costs	716	--	716	12 months
Recoverable Fuel and Purchased Power Costs	656	--	656	12 months
Big Stone II Unrecovered Project Costs – North Dakota	451	--	451	4 months
Minnesota Renewable Resource Rider Accrued Revenues	275	--	275	2 months
General Rate Case Recoverable Expenses	143	--	143	10 months
Deferred Holding Company Formation Costs	55	14	69	15 months
Total Regulatory Assets	$21,326	$129,049	$150,375	
Regulatory Liabilities:				
	$--	$66,740	$66,740	asset lives

Accumulated Reserve for Estimated Removal Costs – Net of Salvage				
Deferred Income Taxes	--	2,452	2,452	asset lives
Deferred Marked-to-Market Gains	40	273	313	65 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	110	116	249 months
South Dakota Transmission Rider Accrued Refund	82	--	82	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	47	--	47	9 months
Minnesota Transmission Rider Accrued Refund	30	--	30	12 months
North Dakota Transmission Rider Accrued Refund	4	--	4	12 months
Total Regulatory Liabilities	$209	$69,575	$69,784	
Net Regulatory Asset Position	$21,117	$59,474	$80,591	

(in thousands)	December 31, 2012 Current	Long-Term	Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$8,411	$109,538	$117,949	see note
Deferred Marked-to-Market Losses	7,949	10,050	17,999	72 months
Conservation Improvement Program Costs and Incentives	3,707	2,560	6,267	18 months
Accumulated ARO Accretion/Depreciation Adjustment	--	4,137	4,137	asset lives
Debt Reacquisition Premiums	268	1,978	2,246	237 months
Big Stone II Unrecovered Project Costs – Minnesota	526	1,618	2,144	45 months
Recoverable Fuel and Purchased Power Costs	1,737	--	1,737	12 months
Deferred Income Taxes	--	1,691	1,691	asset lives
North Dakota Renewable Resource Rider Accrued Revenues	532	1,087	1,619	15 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	--	1,352	1,352	see note
Minnesota Renewable Resource Rider Accrued Revenues	915	--	915	5 months
Big Stone II Unrecovered Project Costs – North Dakota	908	--	908	7 months
Big Stone II Unrecovered Project Costs – South Dakota	100	711	811	97 months
General Rate Case Recoverable Expenses	279	6	285	13 months
North Dakota Transmission Rider Accrued Revenues	110	--	110	12 months
Deferred Holding Company Formation Costs	55	27	82	18 months
South Dakota Transmission Rider Accrued Revenue	2	--	2	12 months
Total Regulatory Assets	$25,499	$134,755	$160,254	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$65,960	$65,960	asset lives
Deferred Income Taxes	--	2,553	2,553	asset lives
Minnesota Transmission Rider Accrued Refund	489	--	489	12 months
Deferred Marked-to-Market Gains	8	210	218	68 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	112	118	252 months
South Dakota – Nonasset-Based Margin Sharing Excess	56	--	56	12 months
Total Regulatory Liabilities	$559	$68,835	$69,394	
Net Regulatory Asset Position	$24,940	$65,920	$90,860	

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC 715, Compensation—Retirement Benefits, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of March 31, 2013 are related to forward purchases of energy scheduled for delivery through December 2018.

Conservation Improvement Program Costs and 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.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 234 months.

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.

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.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule. The March 31, 2013 balance will be amortized on a straight-line basis over a period of 12 months beginning in January 2014.

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 a ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of March 31, 2013.

Deferred Environmental Compliance Costs are related to environmental upgrades at Big Stone Plant that will either be subject to capitalization or recovery through an environmental rider pending approval in North Dakota.

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.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through December 31, 2012 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of March 31, 2013.

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

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

The South Dakota Transmission Rider Accrued Revenues relate to revenues billed for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers net of transmission revenues that are refundable to South Dakota customers as of March 31, 2013.

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.

The Minnesota Transmission Rider Accrued Refund relates to revenues billed for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that are refundable to Minnesota customers as of March 31, 2013.

North Dakota Transmission Rider Accrued Refund relates to revenues billed for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers net of transmission revenues that are refundable to North Dakota customers as of March 31, 2013.

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.

As of March 31, 2013 OTP had recognized, on a pretax basis, $81,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. 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 and level 3 of the fair value hierarchy set forth in ASC 820, Fair Value Measurement.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company’s consolidated balance sheets as of March 31, 2013 and December 31, 2012, and the change in the Company’s consolidated balance sheet position from December 31, 2012 to March 31, 2013 and December 31, 2011 to March 31, 2012:

(in thousands)	March 31, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	$ 1,825	$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	6,109	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	6,469	10,050
Total Assets	14,403	18,501
Current Liability – Marked-to-Market Loss	(14,009)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(40)	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(273)	(210)
Total Liabilities	(14,322)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	$ 81	$ 49

(in thousands)	Year-to-Date March 31, 2013	Year-to-Date March 31, 2012
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$ 49	$ 894
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(49)	(478)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	383
Changes in Fair Value of Contracts Entered into in Current Period	81	227
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 81	$ 610

The $81,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on March 31, 2013 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2nd Qtr 2013	3rd Qtr 2013	Total
Net Gain	$ 50	$ 31	$ 81

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

	Three Months Ended March 31,	
(in thousands)	2013	2012
Net Gains on Forward Electric Energy Contracts	$ 226	$ 194

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

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of March 31, 2013 and December 31, 2012:

	March 31, 2013		December 31, 2012	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$1,764	4	$580	6
Net Credit Risk to Single Largest Counterparty	$832		$285	

OTP had a net credit risk exposure to four counterparties with investment grade credit ratings. OTP had no exposure at March 31, 2013 or December 31, 2012 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The 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. However, the Company does not net offsetting payables and receivables or derivative assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet. The amount of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of March 31, 2013 and December 31, 2012 are indicated in the following table:

(in thousands)	March 31, 2013	December 31, 2012
Derivative assets subject to legally enforceable netting arrangements	1,987	638
Derivative liabilities subject to legally enforceable netting arrangements	(14,009)	(18,234)
Net balance subject to legally enforceable netting arrangements	$ (12,022)	$ (17,596)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of March 31, 2013 and December 31, 2012:

Current Liability – Marked-to-Market Loss (in thousands)	March 31, 2013	December 31, 2012
Loss Contracts Covered by Deposited Funds or Letters of Credit	$2,445	$2,176
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	11,564	16,058
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$14,009	$18,234

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	$11,564	$16,058
Offsetting Gains with Counterparties under Master Netting Agreements	(1,149)	(416)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$10,415	$15,642

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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, 2012 through March 31, 2013:

Common Shares Outstanding, December 31, 2012	36,168,368
Issuances:	
Stock Options Exercised	42,525
Vesting of Restricted Stock Units	1,800
Retirements:	
None	
Common Shares Outstanding, March 31, 2013	36,212,693

Earnings Per Share
The numerator used in the calculation of both basic and diluted earnings per share is earnings available for common shares with no adjustments for the three month periods ended March 31, 2013 and 2012. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting outstanding shares for the following: (1) all potentially dilutive stock options, (2) underlying shares related to nonvested restricted stock units granted to employees, (3) nonvested restricted shares, (4) shares expected to be awarded for stock performance awards granted to executive officers, and (5) shares expected to be issued under the deferred compensation program for directors. The adjustments to the denominators used to calculate basic and diluted earnings per share resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in each of the three month periods ended March 31, 2013 and 2012.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the quarters ended March 31, 2013 and 2012:

Quarter Ended March 31,	Options Outstanding	Range of Exercise Prices
2013	--	--
2012	156,397	$24.93 – $31.34

7. Share-Based Payments

The Company has five share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2013. As of March 31, 2013 the remaining unrecognized compensation expense related to stock-based compensation was approximately $4.3 million (before income taxes) which will be amortized over a weighted-average period of 2.0 years.

Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three months ended March 31, 2013 and 2012 are presented in the table below:

Three months ended
March 31,

(in thousands)		2013		2012
Employee Stock Purchase Plan (15% discount)	$	17	$	39
Restricted Stock Granted to Directors		207		136
Restricted Stock Granted to Employees		92		58
Restricted Stock Units Granted to Employees		75		54
Stock Performance Awards Granted to Executive Officers		1,098		--
Totals	$	1,489	$	287

8. Retained Earnings Restriction

The Company is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of March 31, 2013 the Company was in compliance with the debt covenants. See note 10 to the Company's financial statements on Form 10-K for the year ended December 31, 2012 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 46.3% and 56.7%. OTP's equity to total capitalization ratio including short-term debt was 52.6% as of March 31, 2013. Total capitalization for OTP cannot currently exceed $809 million.

9. Commitments and Contingencies

Construction and Other Purchase Commitments
At December 31, 2012 OTP had commitments under contracts in connection with construction programs aggregating approximately $79,413,000. At March 31, 2013 OTP had commitments under contracts in connection with construction programs aggregating approximately $163,040,000. The increase in construction commitments from December 31, 2012 to March 31, 2013 is mainly for OTP's share of commitments related to the construction of a new air quality control system at Big Stone Plant.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts
OTP has commitments for the purchase of capacity and energy requirements under agreements extending through 2032. OTP did not enter into any agreements for the purchase of additional capacity or energy to meet future capacity and energy requirements in the first quarter of 2013. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2014, 2016 and 2040. In February of 2013, OTP entered into an agreement for the purchase of additional coal to meet a portion of Big Stone Plant's remaining coal requirements for 2013. OTP's share of the additional commitments subsequent to March 31, 2013 total $1,833,000 for 2013.

Contingencies
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, environmental remediation, litigation matters and the resolution of matters related to open tax years. Should all of these known items result in liabilities being incurred, the loss could be as high as $3.5 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, such as possible warranty claims on products that are beyond their warranty period but where a customer may claim to have provided notice of a defect while the product was under warranty. If these claims were to occur, it could result in the Company incurring a significantly greater liability than it anticipates.

Other

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of March 31, 2013 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of March 31, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on March 31, 2013	Restricted due to Outstanding Letters of Credit	Available on March 31, 2013	Available on December 31, 2012
Otter Tail Corporation Credit Agreement	$ 150,000	$ --	$ 733	$ 149,267	$ 149,267
OTP Credit Agreement	170,000	1,271	3,264	165,465	166,811
Total	$ 320,000	$ 1,271	$ 3,997	$ 314,732	$ 316,078

On March 31, 2013 the Company’s construction subsidiary, Foley Company, had $64,000 outstanding in short-term borrowings related to construction activity.

Long-Term Debt Issuance, Retirements and Preferred Stock Redemption

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a $40.9 million unsecured term loan (the Term Loan) to OTP due June 1, 2014, which was fully drawn on March 1, 2013. Borrowings under the Loan Agreement bear interest at LIBOR plus 0.875%. The Loan Agreement permits OTP to use the Term Loan proceeds to fund working capital, capital expenditures and for other corporate purposes. On March 1, 2013, OTP utilized approximately $25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP pays debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately $15.7 million of Term Loan proceeds to satisfy an intercompany note to the Company that had a balance and interest rate designed to equate to the balances and dividend rates of the Company’s cumulative preferred shares which were redeemed on March 1, 2013 for $15.7 million, including $0.2 million in call premiums charged to equity and included with preferred dividends paid and as part of our preferred dividend requirement for the period ending March 31, 2013.

The Loan Agreement contains a number of restrictions on the business of OTP similar to the OTP Credit Agreement, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Loan Agreement also contains affirmative covenants and events of default, as well as a financial covenant under which OTP may not permit the ratio of its Interest bearing Debt to Total Capitalization (as defined in the Loan Agreement) to be greater than 0.60 to 1.00. The Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the Loan Agreement are not guaranteed by any other party. OTP may prepay borrowings without premium or penalty upon notice to JPMorgan as provided in the Loan Agreement. In the event of certain “Senior Indebtedness Prepayment Events” as defined in the Loan Agreement, OTP must offer to prepay a ratable portion of the Term Loan.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of March 31, 2013 and December 31, 2012:

March 31, 2013 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$1,271	$64	$ --	$ 1,335
Long-Term Debt:				
Unsecured Term Loan - LIBOR plus 0.875%, due June 1, 2014	$40,900			$ 40,900
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
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
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Other Obligations - Various up to 3.95% at March 31, 2013			1,681	1,681
Total	$335,900		$ 101,681	$ 437,581
Less: Current Maturities	--		179	179
Unamortized Debt Discount	--		3	3
Total Long-Term Debt	$335,900		$ 101,499	$ 437,399
Total Short-Term and Long-Term Debt (with current maturities)	$337,171	$64	$ 101,678	$ 438,913

December 31, 2012 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$--	$ --	$ --
Long-Term Debt:				
9.000% Notes, due December 15, 2016			$ 100,000	$ 100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	$33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,065			5,065
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	20,070			20,070
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, 2012			1,725	1,725
Total	$320,135		$ 101,725	$ 421,860
Less: Current Maturities	--		176	176
Unamortized Debt Discount	--		4	4
Total Long-Term Debt	$320,135		$ 101,545	$ 421,680
Total Short-Term and Long-Term Debt (with current maturities)	$320,135	$--	$ 101,721	$ 421,856

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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:

	Three Months Ended March 31,	
(in thousands)	2013	2012
Service Cost—Benefit Earned During the Period	$ 1,418	$ 1,294
Interest Cost on Projected Benefit Obligation	3,036	3,108
Expected Return on Assets	(3,632)	(3,608)
Amortization of Prior-Service Cost:		
From Regulatory Asset	83	99
From Other Comprehensive Income1	2	3
Amortization of Net Actuarial Loss:		
From Regulatory Asset	1,663	1,199
From Other Comprehensive Income1	45	32
Net Periodic Pension Cost	$ 2,615	$ 2,127

1Corporate cost included in other nonelectric expenses.

Cash flows—The Company made a discretionary plan contribution of $10,000,000 in January 2013. The Company currently is not required and does not expect to make an additional contribution to the plan in 2013. The Company also made a discretionary plan contribution of $10,000,000 in January 2012.

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

	Three Months Ended March 31,	
(in thousands)	2013	2012
Service Cost—Benefit Earned During the Period	$ 13	$ 11
Interest Cost on Projected Benefit Obligation	352	370
Amortization of Prior-Service Cost:		
From Regulatory Asset	5	5
From Other Comprehensive Income1	13	13
Amortization of Net Actuarial Loss:		
From Regulatory Asset	52	39
From Other Comprehensive Income2	78	43
Net Periodic Pension Cost	$ 513	$ 481

1For 2013 and 2012-$8,000 included in other nonelectric expenses and $5,000 included in electric operation and maintenance expenses.

2For 2013 $30,000 is included in other nonelectric expenses and $48,000 is included in electric operation and maintenance expenses. For 2012 $7,000 is included in other nonelectric expenses and $36,000 is included in electric operation and maintenance expenses.

Postretirement Benefits—Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired OTP and corporate employees, net of effect Medicare Part D Subsidy for the three months ended March 31, 2013 and 2012 of $564,000 and $487,000, respectively, are as follows:

Three Months Ended March 31,

(in thousands)		2013		2012
Service Cost—Benefit Earned During the Period	$	441	$	398
Interest Cost on Projected Benefit Obligation		610		657
Amortization of Transition Obligation:				
From Regulatory Asset		--		182
From Other Comprehensive Income1		--		5
Amortization of Prior-Service Cost:				
From Regulatory Asset		51		51
From Other Comprehensive Income1		1		1
Amortization of Net Actuarial Loss:				
From Regulatory Asset		248		186
From Other Comprehensive Income1		6		5
Net Periodic Postretirement Benefit Cost	$	1,357	$	1,485

1 Corporate cost included in other nonelectric expenses.

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13. Fair Value of Financial Instruments

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

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

Short-Term Debt—The carrying amount approximates fair value because the balance outstanding related to the OTP Credit Agreement is subject to a variable interest rate of LIBOR plus 0.875% and because of the short length of the term on the remaining short-term debt outstanding on March 31, 2013.

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

	March 31, 2013		December 31, 2012	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 37,532	$ 37,532	$ 52,362	$ 52,362
Short-Term Debt	$ (1,335)	$ (1,335)	--	--
Long-Term Debt including Current Maturities	$ (437,578)	$ (508,852)	(421,856)	(491,244)

15. Income Tax Expense – Continuing Operations

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the three month periods ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(in thousands)	2013	2012
Income Before Income Taxes – Continuing Operations	$ 21,120	$ 10,643
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	8,237	4,151
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,589)	(1,987)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	--	(676)
Corporate Owned Life Insurance	(302)	(372)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(223)	(222)
Medicare Part D Subsidy	(4)	(197)
Employee Stock Ownership Plan Dividend Deduction	(190)	(190)
Other Items – Net	(43)	(39)
Income Tax Expense – Continuing Operations	$ 5,886	$ 468
Effective Income Tax Rate – Continuing Operations	27.9 %	4.4 %

17. Discontinued Operations

On February 8, 2013 the Company closed on the sale of substantially all the assets of ShoreMaster for approximately $13.0 million in cash plus a future working capital true up to be finalized within 180 days of closing. On November 30, 2012 the Company completed the sale of the assets of DMI and on February 29, 2012 the Company completed the sale of DMS Health Technologies, Inc. (DMS). Following are summary presentations of the results of discontinued operations for the three-month periods ended March 31, 2013 and 2012:

	For the Three Months Ended March 31,	
(in thousands)	2013	2012
Operating Revenues	$ 2,009	$ 74,051
Operating Expenses	2,707	73,445
Operating (Loss) Income	(698)	606
Interest Charges	--	169
Other Income	412	133
Income Tax (Benefit) Expense	(205)	413
Net (Loss) Income from Operations	(81)	157
Gain (Loss) on Disposition Before Taxes	216	(3,223)
Income Tax Expense (Benefit) on Disposition	6	(134)
Net Gain (Loss) on Disposition	210	(3,089)
Net Income (Loss)	$ 129	$ (2,932)

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of March 31, 2013 and December 31, 2012:

(in thousands)	March 31, 2013	December 31, 2012
Current Assets	$ 4,072	$ 18,487
Investments	--	85
Net Plant	513	520
Assets of Discontinued Operations	$ 4,585	$ 19,092
Current Liabilities	$ 5,551	$ 11,156
Liabilities of Discontinued Operations	$ 5,551	$ 11,156

Included in current liabilities are warranty reserves. Details regarding the warranty reserves follow:

(in thousands)	
Warranty Reserve Balance, December 31, 2012	$ 5,027
Provision for Warranties Used During the Year	120
Less Settlements Made During the Year	(583)
Decrease in Warranty Estimates for Prior Years	(63)
Warranty Reserve Balance, March 31, 2013	$ 4,501

The warranty reserve balance as of December 31, 2012 and March 31, 2013 relates entirely to products produced by DMI and ShoreMaster. Expenses associated with remediation activities of DMI could be substantial. Although the assets of DMI and ShoreMaster have been sold and DMI’s and ShoreMaster’s operating results are reported under discontinued operations in the Company’s consolidated statements of income, the Company retains responsibility for warranty claims related to the products produced by DMI and ShoreMaster prior to the sales of these entities. For DMI’s wind towers, 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.

18. Subsequent Events

Stock Incentive Awards

On April 8, 2013 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 Award	Vesting
Restricted Stock Granted to Nonemployee Directors	16,000	$31.03	25% per year through April 8, 2017
Restricted Stock Granted to Executive Officers	17,000	$31.03	25% per year through April 8, 2017
Stock Performance Awards Granted to Executive Officers	50,200	$37.51	December 31, 2015
Restricted Stock Units Granted to Employees	15,150	$25.30	100% on April 8, 2017

The restricted shares granted to the Company's nonemployee directors and executive officers are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement. 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 100,400 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, 2013 through December 31, 2015. The aggregate target share award is 50,200 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 average projected payout percentage rendered by the simulation was 118.7% of target, which would result in a payout of 57,587 shares with a current fair value of $1,883,000 or $32.70 per share, which equates to $37.51 per targeted share award. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC 718, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

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

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three months ended March 31, 2013 and 2012, followed by a discussion of changes in our consolidated financial position during the three months ended March 31, 2013 and our business outlook for the remainder of 2013.

Comparison of the Three Months Ended March 31, 2013 and 2012

Consolidated operating revenues were $218.0 million for the three months ended March 31, 2013 compared with $219.9 million for the three months ended March 31, 2012. Operating income was $27.2 million for the three months ended March 31, 2013 compared with $18.3 million for the three months ended March 31, 2012. The Company recorded diluted earnings per share from continuing operations of $0.41 for the three months ended March 31, 2013 compared to $0.28 for the three months ended March 31, 2012 and total diluted earnings per share of $0.41 for the three months ended March 31, 2013 compared to $0.20 for the three months ended March 31, 2012.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended March 31, 2013 and 2012 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations (in thousands)	March 31, 2013	March 31, 2012
Operating Revenues:		
Electric	$ 34	$ 35
Nonelectric	13	4
Cost of Goods Sold	13	11
Other Nonelectric Expenses	34	28

Electric

(in thousands)	Three Months Ended March 31, 2013	2012	Change	% Change
Retail Sales Revenues	$ 92,323	$ 81,422	$ 10,901	13.4
Wholesale Revenues – Company Generation	1,633	2,079	(446)	(21.5)
Net Revenue – Energy Trading Activity	345	412	(67)	(16.3)
Other Revenues	6,709	6,090	619	10.2
Total Operating Revenues	$ 101,010	$ 90,003	$ 11,007	12.2
Production Fuel	17,953	15,424	2,529	16.4
Purchased Power – System Use	16,639	14,158	2,481	17.5
Other Operation and Maintenance Expenses	32,447	30,013	2,434	8.1
Asset Impairment Charge	--	432	(432)	(100.0)
Depreciation and Amortization	10,631	10,400	231	2.2
Property Taxes	2,916	2,617	299	11.4
Operating Income	$ 20,424	$ 16,959	$ 3,465	20.4

Electric kwh Sales (in thousands)	Three Months Ended March 31, 2013	2012	Change	% Change
Retail kilowatt-hour (kwh) Sales	1,310,312	1,204,605	105,707	8.8
Wholesale kwh Sales – Company Generation	64,345	95,391	(31,046)	(32.5)
Wholesale kwh Sales – Purchased Power Resold	13,789	6,400	7,389	115.5

The $10.9 million increase in retail sales revenues reflects the following:
a $6.6 million increase in revenue related to an 8.8% increase in retail kilowatt-hour (kwh) sales resulting from colder weather in the first quarter of 2013 compared with the first quarter of 2012, as evidenced by a 33.8% increase in heating-degree days between the quarters,
a $3.6 million increase in revenue related to higher fuel and purchased power prices, in part due to increased market demand for electricity caused by the colder winter and in part due to having to use higher cost generation sources and power purchases to meet the increased demand,
a $0.5 million increase in Transmission Cost Recovery Rider revenues in Minnesota as a result of increased investment in transmission assets, and
a $0.2 million increase in Renewable Resource Cost Recovery Rider revenue in North Dakota.

Wholesale electric revenues from company-owned generation decreased $0.4 million, despite a 16.4% increase in wholesale electric prices, mainly as a result of a 32.5% decrease in wholesale kwh sales as a greater proportion of available generation was used to serve retail load.

Other electric operating revenues increased $0.6 million as a result of:
a $1.3 million increase in Midwest Independent Transmission System Operator (MISO) Schedules 26 and 26A transmission tariff revenue, driven in part by returns on and recovery of CapX2020 and MISO-designated MVP investment costs and operating expenses,
offset by:
a $0.7 million reduction in MISO Schedule 1 transmission tariff revenue related to a tariff change that went into effect on August 28, 2012.

Fuel costs increased $2.5 million as a result of an 11.4% increase in kwhs generated from Otter Tail Power Company (OTP) steam-powered and combustion turbine generators, combined with a 4.5% increase in the cost of fuel per kwh generated. Generation levels increased in response to higher demand due to more seasonal weather in the first quarter of 2013 compared to the first quarter of 2012. The average cost of fuel per kwh of generation increased, in part, because OTP's Coyote Station was shut down for generator repairs during the first seven weeks of 2013.

The cost of purchased power for retail sales increased $2.5 million as a result of a 14.9% increase in kwhs purchased, combined with a 2.3% increase in the cost per kwh purchased. The increase in kwhs purchased was driven by increased demand due to the colder weather in 2013.

Electric operating and maintenance expenses increased $2.4 million mainly due to the following:
a $1.1 million increase in MISO Schedules 26 and 26A transmission service charges related to increasing investments in regional CapX2020 and MISO-designated Multi-Value Projects (MVPs),
a $0.9 million increase in labor and benefit expenses related to increases in pension and retirement health benefit costs resulting from reductions in the discount rates related to projected benefit obligations, and
a $0.3 million Minnesota Pollution Control Agency annual operations fee paid in the first quarter of 2013 (this annual fee was paid in the second quarter in 2012).

Otter Tail Energy Services Company (OTESCO) recorded a $0.4 million asset impairment charge related to wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota in the first quarter of 2012 as a potential sale of the rights did not occur as expected. OTESCO reported no activity in the first quarter of 2013.

The $0.3 million increase in property tax expense is due to recent investments in transmission and distribution property, mainly in Minnesota.

Manufacturing

(in thousands)	Three Months Ended March 31, 2013	2012	Change	% Change
Operating Revenues	$ 53,166	$ 59,434	$ (6,268)	(10.5)
Cost of Goods Sold	39,326	44,667	(5,341)	(12.0)
Operating Expenses	4,498	5,046	(548)	(10.9)
Depreciation and Amortization	2,993	3,018	(25)	(0.8)
Operating Income	$ 6,349	$ 6,703	$ (354)	(5.3)

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

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, decreased $6.2 million as a result of lower sales volume mainly due to reduced demand from customers in end markets serving the construction, energy and lawn and garden equipment industries.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased by $0.1 million over the first quarter of 2012.

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

Cost of goods sold at BTD decreased $4.8 million as a result of reductions in direct labor and material costs related to decreased sales volume.

Cost of goods sold at T.O. Plastics decreased $0.5 million as a result of favorable raw material pricing and continuing productivity improvements.

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

Operating expenses at BTD increased $0.6 million due to a decrease in compensation related to the reduction in sales.

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

Construction

(in thousands)	Three Months Ended March 31, 2013	2012	Change	% Change
Operating Revenues	$ 26,425	$ 35,617	$ (9,192)	(25.8)
Cost of Goods Sold	24,276	38,693	(14,417)	(37.3)
Operating Expenses	3,386	3,280	106	3.2
Depreciation and Amortization	462	434	28	6.5
Operating Loss	$ (1,699)	$ (6,790)	$ 5,091	75.0

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

Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, decreased $5.3 million, mainly as a result of a reduction in work volume between the quarters as several large projects were near completion in 2012.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, decreased $3.9 million between the quarters as a result of a decrease in construction activity due, in part, to a harsher winter in 2013 delaying the start of many construction projects relative to the early start to construction that was facilitated by extremely mild weather in the first quarter of 2012. Aevenia's first quarter 2012 revenues also included $1.3 million from Moorhead Electric, Inc., an Aevenia subsidiary that was sold in October 2012.

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

Cost of goods sold at Foley decreased $11.2 million as a result of the reduction in work volume and a $6.0 million reduction in cost overruns between the quarters on major projects nearing completion during the quarters.

Cost of goods sold at Aevenia decreased $3.2 million between the quarters as a result of a decrease in construction activity due, in part, to a harsher winter in 2013 delaying the start of many construction projects relative to the early start to construction that was facilitated by extremely mild weather in the first quarter of 2012.

Plastics

(in thousands)	Three Months Ended March 31, 2013	2012	Change	% Change
Operating Revenues	$ 37,400	$ 34,875	$ 2,525	7.2
Cost of Goods Sold	28,473	26,947	1,526	5.7
Operating Expenses	1,436	1,363	73	5.4
Depreciation and Amortization	774	813	(39)	(4.8)

Operating Income	$	6,717	$	5,752	$	965	16.8

The increase in Plastics segment revenue is the result of a 6.7% increase in pounds of polyvinyl chloride (PVC) pipe sold, combined with a 0.5% increase in the price per pound of pipe sold. Sales volume increased as construction and housing markets improved in the South Central and Southwest regions of the United States. Sales volume increases in these regions were partially offset by lower sales in the North Central United States due to a harsher winter in this region in 2013. The increase in costs of goods sold was mostly due to the increase in pounds of pipe sold, but was partially offset by a 1.0% decrease in the cost per pound of pipe related to a slight decrease in PVC resin prices.

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.

	Three Months Ended March 31,			%
(in thousands)	2013	2012	Change	Change
Operating Expenses	$ 4,492	$ 4,241	$ 251	5.9
Depreciation and Amortization	60	128	(68)	(53.1)

Corporate operating expense increases totaling $1.1 million in labor and benefit costs related to staffing additions to support the manufacturing and infrastructure platforms and stock incentive award accruals resulting from the strong performance of our common stock price as measured against the stock performances of our peer group of companies in the Edison Electric Institute Index in the first quarter of 2013, were offset by decreases of $0.7 million in professional and contracted services expenses and $0.1 million in other corporate expenses.

Interest Charges

The $1.6 million decrease in interest charges in the first three months of 2013 compared with the first three months of 2012, is mostly due to the July 2012 early redemption of the corporation's $50 million, 8.89% senior unsecured note, which resulted in a $1.1 million decrease in interest charges between quarters. Short-term debt interest decreased $0.3 million as a result of a reduction in the average balance of short-term debt outstanding between the quarters along with reduced rates and fees on our line of credit facilities. A $0.1 million increase in capitalized interest expense at OTP also contributed to the decrease in interest charges.

Income Taxes – Continuing Operations

Income taxes - continuing operations increased $5.4 million in the first quarter of 2013 compared with the first quarter of 2012.
The following table provides a reconciliation of income tax expense calculated at the Company's net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the three month periods ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(in thousands)	2013	2012
Income Before Income Taxes – Continuing Operations	$ 21,120	$ 10,643
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	8,237	4,151
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,589)	(1,987)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	--	(676)
Corporate Owned Life Insurance	(302)	(372)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(223)	(222)

Medicare Part D Subsidy	(4)	(197)
Employee Stock Ownership Plan Dividend Deduction	(190)	(190)
Other Items - Net	(43)	(39)
Income Tax Expense – Continuing Operations	$ 5,886	$ 468
Effective Income Tax Rate – Continuing Operations	27.9 %	4.4 %

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

On February 8, 2013 we closed on the sale of substantially all the assets of ShoreMaster, Inc. (ShoreMaster) for approximately $13.0 million in cash plus a future working capital true up of approximately $2.3 million expected to be received within 180 days of closing. In the first quarter of 2013, we paid approximately $0.8 million in expenses related to the sale of ShoreMaster and we also paid a $1.7 million working capital settlement to the purchaser of DMS Health Technologies, Inc. (DMS), which was sold on February 29, 2012. On November 30, 2012 we completed the sale of the assets of DMI Industries, Inc. (DMI). The financial position of ShoreMaster and DMI and the results of operations and cash flows of ShoreMaster, DMI and DMS are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the three month periods ended March 31, 2013 and 2012:

	For the Three Months Ended March 31,	
(in thousands)	2013	2012
Operating Revenues	$ 2,009	$ 74,051
Operating Expenses	2,707	73,445
Operating (Loss) Income	(698)	606
Interest Charges	--	169
Other Income	412	133
Income Tax (Benefit) Expense	(205)	413
Net (Loss) Income from Operations	(81)	157
Gain (Loss) on Disposition Before Taxes	216	(3,223)
Income Tax Expense (Benefit) on Disposition	6	(134)
Net Gain (Loss) on Disposition	210	(3,089)
Net Income (Loss)	$ 129	$ (2,932)

FINANCIAL POSITION

The following table presents the status of our lines of credit as of March 31, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on March 31, 2013	Restricted due to Outstanding Letters of Credit	Available on March 31, 2013	Available on December 31, 2012
Otter Tail Corporation Credit Agreement	$150,000	$--	$ 733	$149,267	$149,267
OTP Credit Agreement	170,000	1,271	3,264	165,465	166,811
Total	$320,000	$1,271	$ 3,997	$314,732	$316,078

On March 31, 2013 our construction subsidiary, Foley, had $64,000 outstanding in short-term borrowings related to construction activity.

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 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 (the 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 2013 through 2017 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, 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 five 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 and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 8 to consolidated financial statement for more information. The decision to declare a quarterly dividend is reviewed quarterly by the Board of Directors.

Cash provided by operating activities from continuing operations was $10.2 million for the three months ended March 31, 2013 compared with $9.0 million for the three months ended March 31, 2012. Cash provided by operating activities from continuing operations reflects an $8.1 million increase in net income from continuing operations offset by a $5.3 million increase in cash used for working capital items mainly due to a decrease in accounts payable and other current liabilities in the first quarter of 2013 compared to the first quarter of 2012, mostly due to the change in annual bonuses paid between the periods.

Net cash used in investing activities of continuing operations was $23.5 million for the three months ended March 31, 2013 compared to $35.6 million for the three months ended March 31, 2012 due to a $12.4 million decrease in cash used for capital expenditures at the electric utility between the quarters. Although the level of construction activity at OTP was similar between the quarters, OTP's $33.3 million in capital expenditures in the first quarter of 2012 included a $14.0 million reduction in construction-related accounts payable. Net proceeds from the sale of discontinued operations of $10.5 million in the first quarter of 2013 reflect $12.2 million in net proceeds from the sale of the assets of ShoreMaster less a $1.7 million working capital settlement paid to the buyer of DMS, which we sold in the first quarter of 2012. Net proceeds from the sale of discontinued operations of $24.4 million in the first quarter of 2012, which were used to pay down short-term borrowings and for other corporate purposes, reflect proceeds, net of selling costs, of $24.1 million from the sale of DMS and $0.3 million from the January 2012 sale of the assets of Aviva Sports, Inc., a wholly owned subsidiary of ShoreMaster. Net cash used in investing activities of discontinued operations of $11.9 million in the first quarter of 2012 reflects cash used by DMS to purchase assets held under operating leases.

Net cash used in financing activities of continuing operations of $8.6 million reflects $2.5 million in proceeds from short term borrowings and the issuance of common stock offset by $11.3 million in common and preferred stock dividend payments. On March 1, 2013 OTP used proceeds from a $40.9 million unsecured term loan to fund the redemption of all $25.1 million of the then outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds, and to pay off an intercompany note to us that mirrored our $15.5 million in outstanding cumulative preferred shares, which were also redeemed on March 1, 2013.

CAPITAL REQUIREMENTS

2013-2017 Capital Expenditures

We plan to invest in generation and transmission projects for the Electric segment that are expected to positively impact our earnings and returns on capital. In addition to the Big Stone Plant air quality control system project, current Electric segment projects include investment in three MISO-determined MVP transmission projects, one of which is a CapX2020 project, and investment in one other CapX2020 transmission project.

We have revised our consolidated capital expenditures expectation for 2013 from the range of $200 million to $210 million anticipated in our initial capital budget to a range of $165 million to $175 million. In the first quarter of 2013 Otter Tail Power Company revised downward its estimates of its share of capital expenditures required for the construction of a new air quality control system at Big Stone Plant from $265 million to $218 million as a result of a reduction in expected costs due to prudent design changes, low bids in a buyer’s market and in-house project management. In addition there have been changes to Big Stone area transmission project capital costs.

The following table shows the corporation's initial and revised 2013 through 2017 anticipated capital expenditures and electric utility average rate base:

From Page 56 of Otter Tail Corporation's 2012 Annual Report on Form 10-K

(in millions)	2012 Actual	2013	2014	2015	2016	2017
Capital Expenditures:						
Electric Segment:						
Transmission		$60	$45	$56	$69	$118
Environmental		89	99	72	1	--
Other		33	41	42	43	43
Total Electric Segment	$102	$182	$185	$170	$113	$161
Manufacturing and Infrastructure Segments	14	22	19	19	15	20
Total Capital Expenditures	$116	$204	$204	$189	$128	$181
Total Electric Utility Average Rate Base	$694	$789	$919	$1,061	$1,134	$1,197

Revised - May 2013

(in millions)	2012 Actual	2013	2014	2015	2016	2017
Capital Expenditures:						
Electric Segment:						
Transmission		$51	$61	$45	$105	$62
Environmental		74	79	55	1	--
Other		34	36	37	36	39
Total Electric Segment	$102	$159	$176	$137	$142	$101
Manufacturing and Infrastructure Segments	14	12	19	19	15	20
Total Capital Expenditures	$116	$171	$195	$156	$157	$121
Total Electric Utility Average Rate Base	$694	$767	$890	$999	$1,067	$1,133

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2013 through 2017 timeframe. Our 2013 through 2017 electric utility capital expenditures are subject to periodic review and revision, and actual construction costs may be lower or higher than these estimates due to numerous factors. Some of the factors include: the cost and efficiency of construction labor, equipment and materials; project scope and design changes; changes in construction schedules; business and economic conditions; the cost and availability of capital; and environmental requirements. Changes in the estimates to the actual construction costs could have an impact on the growth in the utility's rate base and future earnings. We intend to maintain the equity-to-total capitalization ratio near its present level of 52% in our Electric segment and will seek to earn the electric utility's authorized overall return on equity of approximately 10.5% in its regulatory jurisdictions.

Contractual Obligations

Our contractual obligations reported in the table on page 51 of our Annual Report on Form 10-K for the year ended December 31, 2012 have increased by $92 million. Our obligations for the purchase of coal have increased by $2 million for 2013 related to an agreement entered into in February of 2013 for the purchase of additional coal to meet a portion of Big Stone Plant's remaining coal requirements for 2013. Our long-term debt obligations have increased by $41 million for 2014 related to OTP's March 2013 borrowings under an unsecured term loan, and decreased by $5 million for 2017 and $20 million for the years beyond 2017 related to the early redemption of all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on March 1, 2013. As a result of the March 1, 2013 debt issuance and redemptions, our interest obligations on long-term debt decreased by $1 million for 2013, $2 million for 2014 and 2015, $2 million for 2016 and 2017 and $5 million for the years beyond 2017. Other Purchase Obligations have increased by $22 million for 2013 and $62 million for 2014 and 2015 mainly for contracts related to the construction of a new air quality control system at Big Stone Plant.

CAPITAL RESOURCES

Short-Term Debt

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Credit Agreement), which is an unsecured $150 million revolving credit facility that we can draw on to refinance certain indebtedness and support our operations and the operations of our subsidiaries. Borrowings under the Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. The Credit Agreement expires on October 29, 2017. Under the Credit Agreement, we are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Credit Agreement contains a number of restrictions on us and the businesses of Varistar and its material subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, 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 $40 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million on the terms and subject to the conditions described in the Credit Agreement.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement) that provides for 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 1.25%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. The OTP Credit Agreement is set to expire on October 29, 2017. 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, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a $40.9 million unsecured term loan (the Term Loan) to OTP due June 1, 2014, which was fully drawn on March 1, 2013. Borrowings under the Loan Agreement bear interest at LIBOR plus 0.875%. The Loan Agreement permits OTP to use the Term Loan proceeds to fund working capital, capital expenditures and for other corporate purposes. On March 1, 2013, OTP utilized approximately $25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP pays debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately $15.7 million of Term Loan proceeds to satisfy an intercompany note to us that had a balance and interest rate designed to equate to the balances and dividend rates of our cumulative preferred shares which were redeemed on March 1, 2013 for $15.7 million, including $0.2 million in call premiums charged to equity and included with preferred dividends paid and as part of our preferred dividend requirement for the period ending March 31, 2013.

The Loan Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Loan Agreement also contains affirmative covenants and events of default. The Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the Loan Agreement are not guaranteed by any other party. OTP may prepay borrowings without premium or penalty upon notice to JPMorgan as provided in the Loan Agreement. In the event of certain “Senior Indebtedness Prepayment Events” as defined in the Loan Agreement, OTP must offer to prepay a ratable portion of the Term Loan.

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 note purchase agreement relating to OTP's $140 million 4.63% senior unsecured notes due December 1, 2021 (the 2011 Note Purchase Agreement) each states that OTP 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 OTP 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 2011 Note Purchase Agreement.

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, and each contains a number of restrictions on OTP. These include restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Financial Covenants

As of March 31, 2013 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 borrowing agreements are subject to certain financial covenants. Specifically:

Under the Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement. As of March 31, 2013 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 3.30 to 1.00.

Under the OTP Credit Agreement and the Loan Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.

Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, 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 agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of March 31, 2013 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 3.51 to 1.00.

As of March 31, 2013 our interest-bearing debt to total capitalization was 0.45 to 1.00 on a fully consolidated basis and 0.47 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $10.7 million, but our line of credit borrowing limits are only restricted by $4.0 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.

2013 BUSINESS OUTLOOK

We are reaffirming our consolidated earnings per share from continuing operations guidance for 2013 to be in the range of $1.30 to $1.55. This guidance reflects the current mix of businesses owned by us and considers the cyclical nature of some of our businesses. It also reflects challenges presented by current economic conditions, as well as our plans and strategies for improving future operating results.

Segment components of our 2013 earnings per share guidance range are as follows:

	Previous 2013 EPS Guidance		Current 2013 EPS Guidance	
	Low	High	Low	High
Electric	$1.06	$1.11	$1.02	$1.07
Manufacturing	$0.31	$0.36	$0.28	$0.33
Construction	$0.06	$0.11	$0.06	$0.11
Plastics	$0.16	$0.21	$0.25	$0.30
Corporate	($0.29)	($0.24)	($0.31)	($0.26)
Total – Continuing Operations	$1.30	$1.55	$1.30	$1.55

Contributing to the earnings guidance for 2013 are the following items:

We are reducing our previous guidance for 2013 in our Electric segment. The change is primarily based on an updated capital expenditure plan which is lower than original expectations. As a result of the reduction in anticipated capital expenditures, our Electric segment is now expecting lower rider recovery revenues and lower AFUDC earnings in 2013. Also, the Electric segment continues to expect lower conservation improvement program incentives and increases in operating and maintenance expenses due to higher benefit and administrative costs. OTP's pension benefit costs for our noncontributory funded pension plan are expected to increase in 2013 as a result of a change in the assumed rate of return on pension plan assets from 8.0% in 2012 to 7.75% in 2013 and a decrease in the estimated discount rate used to determine annual benefit cost accruals from 5.15% in 2012 to 4.50% in 2013.

We now expect earnings from our Manufacturing segment to be flat in 2013 compared with 2012 due to the following factors:

- Order volume across the end markets of the construction, energy and lawn and garden industries have softened for the remainder of 2013 affecting BTD's customers in these industries.

- Lower earnings are now expected in 2013 at T.O. Plastics, primarily due to a key customer announcing plans to produce certain products in house rather than outsource the work to T.O. Plastics.

- Backlog for the manufacturing companies is approximately $97 million for 2013 compared with $103 million one year ago.

We are maintaining our 2013 earnings per share guidance for our Construction segment. Segment net income is expected to be higher in 2013 than 2012 due to improved cost control processes in construction management and selective bidding on projects with the potential for higher margins. Foley's performance on certain large projects negatively impacted 2012 results. These projects were substantially completed in 2012 and Foley's internal bidding and estimating project review procedures have been improved such that we do not expect to see similar losses in 2013. Backlog in place for the construction businesses is $100 million for 2013 compared with $83 million one year ago.

We now expect an increase in Plastics segment net income in 2013 based on the strength of its first quarter performance.

Corporate general and administrative costs are expected to increase from our previous 2013 guidance due to an expected increase in employee benefit costs associated with stock incentive awards based on the strong performance of our common stock price as measured against the stock performances of our peer group of companies in the Edison Electric Institute Index in the first quarter of 2013.

We will continue to review our portfolio of companies to see where additional opportunities may exist to improve our risk profile, improve credit metrics and generate additional sources of cash to support the future capital expenditure plans of our Electric segment. This will result in a larger percentage of our earnings coming from OTP, our most stable and relatively predictable business, and is consistent with our strategy to grow this business given its current investment opportunities.

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 56 through 60 of our Annual Report on Form 10-K for the year ended December 31, 2012. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2013.

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:

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and could increase borrowing costs and pension plan and postretirement health care expenses.

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are not able to access capital at competitive rates, our ability to implement our business plans may be adversely affected.

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 2013. 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.

We currently have $7.3 million of goodwill and a $1.1 million indefinite-lived trade name recorded on our consolidated balance sheet related to the acquisition of Foley Company in 2003. Foley Company generated a large operating loss in 2012 due to significant cost overruns on certain construction projects. If operating margins do not meet our projections, the reductions in anticipated cash flows from Foley Company may indicate that its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived trade name associated with Foley along with a corresponding charge against earnings.

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 business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

We may, from time to time, sell assets 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 assets sold and other potential liabilities. The sale of any of our businesses could expose us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

Our plans to grow and operate our manufacturing and infrastructure businesses could be limited by state law.

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.

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.

We may experience fluctuations in revenues and expenses related to our electric 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.

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 (CO_2) emissions, could affect OTP's operating costs and the costs of supplying electricity to its customers.

Competition from foreign and domestic manufacturers, the price and availability of raw materials 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 or contracts by our construction businesses could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

Our construction subsidiaries enter into contracts 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.

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

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2013 we had exposure to market risk associated with interest rates because we had $1.3 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.25% under OTP's $170 million revolving credit facility.

The majority 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. As of March 31, 2013 we had $40.9 million of long-term debt outstanding under an unsecured term loan subject to a variable interest rate of LIBOR plus 0.875%. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate in effect on March 31, 2013, annualized interest expense and pre-tax earnings would change by approximately $409,000.

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

The companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, aluminum and Polystyrene (PS) and other plastics resins. The price and availability of these raw materials could affect the revenues and earnings of our Manufacturing segment.

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 volume has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of March 31, 2013 OTP had recognized, on a pretax basis, $81,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase contracts that are marked to market as of March 31, 2013, 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 entered into with different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of $31,000.

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 March 31, 2013 where purchases were not at the same delivery points as the offsetting sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on our consolidated balance sheets as of March 31, 2013 and December 31, 2012, and the change in our consolidated balance sheet position from December 31, 2012 to March 31, 2013 and December 31, 2011 to March 31, 2012:

(in thousands)	March 31, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	$1,825	$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	6,109	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	6,469	10,050
Total Assets	14,403	18,501
Current Liability – Marked-to-Market Loss	(14,009)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(40)	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(273)	(210)
Total Liabilities	(14,322)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	$81	$ 49

(in thousands)	Year-to-Date March 31, 2013	Year-to-Date March 31, 2012
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$ 49	$ 894
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(49)	(478)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	383
Changes in Fair Value of Contracts Entered into in Current Period	81	227
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 81	$ 610

The $81,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on March 31, 2013 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2nd Qtr 2013	3rd Qtr 2013	Total
Net Gain	$ 50	$ 31	$ 81

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

(in thousands)	Three Months Ended March 31, 2013	2012
Net Gains on Forward Electric Energy Contracts	$ 226	$ 194

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

March 31, 2013 was $832,000. As of March 31, 2013 OTP had a net credit risk exposure of $1,764,000 from four counterparties with investment grade credit ratings. OTP had no exposure at March 31, 2013 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $1,764,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after March 31, 2013. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of March 31, 2013, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of March 31, 2013.

During the fiscal quarter ended March 31, 2013, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Other

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

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 29 through 35 of the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

Item 5. Other Information

On May 9, 2013, OTP entered into a Wind Energy Purchase Agreement (the "Wind PPA") with Ashtabula Wind III, LLC ("AW III") under which OTP agrees to purchase all of the output from AW III's wind-energy conversion electric generating facility (including any associated renewable energy credits) for an agreed price for a term of 25 years with delivery expected to begin in the third quarter of 2013. The facility has a total nameplate capacity of approximately 62.4 megawatts.

Under the Wind PPA AW III guarantees a minimum level of availability for the facility on a rolling twenty-four calendar month basis, with liquidated damages payable in connection with any availability shortfall as provided in the Wind PPA. OTP is obligated to purchase all of the facility's output that qualifies as renewable energy under the Wind PPA, that is measured by the electric metering devices installed pursuant to the Wind PPA, and that is delivered to OTP at the agreed point of delivery, except as specified in the Wind PPA. In the event OTP curtails the delivery of any output that it is required to purchase under the Wind PPA, it will be obligated to pay for such output as if it had been delivered, as provided in the Wind PPA.

The Wind PPA also provides for the establishment by AW III of a fund to be maintained throughout the term of the agreement on which OTP may draw any amounts, including damages and indemnification amounts, owing to it under the Wind PPA. In the event OTP's senior unsecured debt rating falls below investment grade or OTP fails to maintain a credit rating from a rating agency, OTP will be obligated to maintain a fund on which AW III may draw amounts to which it is entitled under the Wind PPA.

AW III grants to OTP under the Wind PPA a one-time option to purchase the facility property. In addition, OTP has a right of first offer with respect to the facility in connection with any offer by AW III to convey the facility property to an unaffiliated third party as provided in the Wind PPA.

AW III is affiliated with NextEra Energy. OTP has long term power purchase agreements for the purchase of energy from 14 wind turbines near Edgeley, North Dakota and 13 wind turbines at the Langdon Wind Energy Center that are owned by affiliates of NextEra Energy. OTP also shares use of common facilities under common facility agreements with affiliates of NextEra Energy at the Ashtabula Wind Center and the Langdon Wind Energy Center, each located in North Dakota. Additionally, an affiliate of NextEra Energy provides maintenance services for the assets OTP owns at the Ashtabula Wind Center and the Langdon Wind Energy Center under long-term operating and maintenance agreements.

Item 6. Exhibits

10.1 General Work Construction Agreement, dated as of February 1, 2013, between Otter Tail Power Company, a Minnesota corporation (OTP), in its capacity as agent for itself, Northwestern Corporation d/b/a NorthWestern Energy and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and Graycor Industrial Constructors Inc.*

10.2 Credit Agreement, dated as of March 1, 2013, between Otter Tail Power Company and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on March 7, 2013).

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

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

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

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101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Confidential information has been omitted from this Exhibit and filed separately with the Commission pursuant to a confidential treatment request under Rule 24b-2.

SIGNATURES

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

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer
(Chief Financial Officer/Authorized Officer)

Dated: May 10, 2013

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EXHIBIT INDEX

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