Otter Tail Corp
Form 10-Q
August 09, 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 June 30, 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:

July 31, 2013 – 36,269,263 Common Shares ($5 par value)

OTTER TAIL CORPORATION

INDEX

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	June 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$42,275	$52,362
Accounts Receivable:		
Trade—Net	99,370	91,170
Other	9,189	7,684
Inventories	73,411	69,336
Deferred Income Taxes	19,362	30,964
Unbilled Revenues	11,245	15,701
Costs and Estimated Earnings in Excess of Billings	5,122	3,663
Regulatory Assets	20,313	25,499
Other	12,009	8,161
Assets of Discontinued Operations	1,132	19,092
Total Current Assets	293,428	323,632
Investments	9,342	9,471
Other Assets	27,135	26,222
Goodwill	38,971	38,971
Other Intangibles—Net	13,816	14,305
Deferred Debits		
Unamortized Debt Expense	4,476	5,529
Regulatory Assets	131,545	134,755
Total Deferred Debits	136,021	140,284
Plant		
Electric Plant in Service	1,434,511	1,423,303
Nonelectric Operations	190,536	186,094
Construction Work in Progress	107,248	77,890
Total Gross Plant	1,732,295	1,687,287
Less Accumulated Depreciation and Amortization	659,539	637,835
Net Plant	1,072,756	1,049,452

Total Assets	$1,591,469	$1,602,337

See accompanying notes to consolidated financial statements.

2

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	June 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$1,117	$ --
Current Maturities of Long-Term Debt	182	176
Accounts Payable	97,837	88,406
Accrued Salaries and Wages	16,185	20,571
Billings In Excess Of Costs and Estimated Earnings	16,158	16,204
Accrued Taxes	8,690	12,047
Derivative Liabilities	13,294	18,234
Other Accrued Liabilities	5,985	6,334
Liabilities of Discontinued Operations	5,332	11,156
Total Current Liabilities	164,780	173,128
Pensions Benefit Liability	108,342	116,541
Other Postretirement Benefits Liability	60,082	58,883
Other Noncurrent Liabilities	24,537	22,244
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	171,320	171,787
Deferred Tax Credits	29,258	31,299
Regulatory Liabilities	70,048	68,835
Other	523	466
Total Deferred Credits	271,149	272,387
Capitalization		
Long-Term Debt, Net of Current Maturities	437,353	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—36,267,963 Shares; 2012—36,168,368 Shares	181,340	180,842

Premium on Common Shares	254,947	253,296
Retained Earnings	93,221	92,221
Accumulated Other Comprehensive Loss	(4,282)	(4,385)
Total Common Equity	525,226	521,974
Total Capitalization	962,579	959,154
Total Liabilities and Equity	$1,591,469	$ 1,602,337

See accompanying notes to consolidated financial statements.

3

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating Revenues				
Electric	$82,838	$78,940	$183,814	$168,909
Nonelectric	129,551	132,461	246,529	262,382
Total Operating Revenues	212,389	211,401	430,343	431,291
Operating Expenses				
Production Fuel – Electric	15,603	12,455	33,556	27,879
Purchased Power - Electric System Use	11,245	12,328	27,884	26,486
Electric Operation and Maintenance Expenses	35,805	32,407	68,252	62,420
Asset Impairment Charge - Electric	--	--	--	432
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	103,937	108,426	195,999	218,722
Other Nonelectric Expenses	12,176	12,979	25,954	26,881
Depreciation and Amortization	14,835	14,890	29,755	29,683
Property Taxes - Electric	3,009	2,670	5,925	5,287
Total Operating Expenses	196,610	196,155	387,325	397,790
Operating Income	15,779	15,246	43,018	33,501
Interest Charges	6,877	8,472	13,857	17,066
Other Income	696	644	1,557	1,626
Income from Continuing Operations Before Income Taxes	9,598	7,418	30,718	18,061
Income Taxes – Continuing Operations	2,094	517	7,980	985
Net Income from Continuing Operations	7,504	6,901	22,738	17,076
Discontinued Operations				
Income - net of Income Tax Expense (Benefit) of $131, $3,093, ($75) and $3,506 for the respective periods	197	3,657	116	3,814
Impairment Loss - net of Income Tax (Benefit) of $0, ($18,114), $0 and ($18,114) for the respective periods	--	(27,459)	--	(27,459)
(Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of $0, ($35), $6, and ($169) for the respective periods	--	(455)	210	(3,544)
Net Income (Loss) from Discontinued Operations	197	(24,257)	326	(27,189)
Net Income (Loss)	7,701	(17,356)	23,064	(10,113)
Preferred Dividend Requirements and Other Adjustments	--	184	513	368
Earnings (Loss) Available for Common Shares	$7,701	$(17,540)	$22,551	$(10,481)
Average Number of Common Shares Outstanding—Basic	36,170,353	36,031,447	36,122,742	36,013,313
Average Number of Common Shares Outstanding—Diluted	36,373,606	36,222,944	36,325,527	36,204,810

Basic Earnings (Loss) Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.21	$0.19	$0.61	$0.46
Discontinued Operations	--	(0.68)	0.01	(0.75)
	$0.21	$(0.49)	$0.62	$(0.29)
Diluted Earnings (Loss) Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.21	$0.19	$0.61	$0.46
Discontinued Operations	--	(0.67)	0.01	(0.75)
	$0.21	$(0.48)	$0.62	$(0.29)
Dividends Declared Per Common Share	$0.2975	$0.2975	$0.5950	$0.5950

See accompanying notes to consolidated financial statements.

4

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

(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net Income (Loss)	$7,701	$(17,356)	$23,064	$(10,113)
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	(80)	4	(85)	108
Income Tax Benefit (Expense)	28	(2)	39	(43)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(52)	2	(71)	65
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 12)	146	102	291	204
Income Tax (Expense)	(59)	(40)	(117)	(81)
Pension and Postretirement Benefit Plans – net-of-tax	87	62	174	123
Total Other Comprehensive Income	35	64	103	188
Total Comprehensive Income	$7,736	$(17,292)	$23,167	$(9,925)

See accompanying notes to consolidated financial statements.

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

(in thousands)	Six Months Ended June 30, 2013	2012
Cash Flows from Operating Activities		
Net Income (Loss)	$23,064	$(10,113)
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net (Gain) Loss from Sale of Discontinued Operations	(210)	3,544
Net (Income) Loss from Discontinued Operations	(116)	23,645
Depreciation and Amortization	29,755	29,683
Asset Impairment Charge	--	432
Deferred Tax Credits	(955)	(1,045)
Deferred Income Taxes	9,882	3,180
Change in Deferred Debits and Other Assets	7,519	9,960
Discretionary Contribution to Pension Plan	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	4,971	6,995
Allowance for Equity-Other Funds Used During Construction	(567)	(378)
Change in Derivatives Net of Regulatory Deferral	486	748
Stock Compensation Expense—Equity Awards	786	612
Other—Net	867	3,133
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(10,126)	(7,551)
Change in Inventories	(4,075)	(866)
Change in Other Current Assets	(783)	(2,598)
Change in Payables and Other Current Liabilities	(1,362)	5,028
Change in Interest and Income Taxes Receivable/Payable	(313)	(8,832)
Net Cash Provided by Continuing Operations	48,823	45,577
Net Cash Used in Discontinued Operations	(1,971)	(60)
Net Cash Provided by Operating Activities	46,852	45,517
Cash Flows from Investing Activities		
Capital Expenditures	(51,153)	(64,989)
Net Proceeds from Disposal of Noncurrent Assets	1,603	2,223
Net Increase in Other Investments	(25)	(268)
Net Cash Used in Investing Activities - Continuing Operations	(49,575)	(63,034)
Net Proceeds from Sale of Discontinued Operations	12,842	24,278
Net Cash Provided by (Used in) Investing Activities - Discontinued Operations	193	(12,822)
Net Cash Used in Investing Activities	(36,540)	(51,578)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	--	6,419
Net Short-Term Borrowings	1,117	11,274
Proceeds from Issuance of Common Stock	1,462	--
Common Stock Issuance Expenses	--	(86)
Payments for Retirement of Capital Stock	(15,723)	(110)
Proceeds from Issuance of Long-Term Debt	40,900	--

Short-Term and Long-Term Debt Issuance Expenses	(52)	(10)
Payments for Retirement of Long-Term Debt	(25,222)	(81)
Dividends Paid and Other Distributions	(22,097)	(21,980)
Net Cash Used in Financing Activities - Continuing Operations	(19,615)	(4,574)
Net Cash Used in Financing Activities - Discontinued Operations	--	(3,344)
Net Cash Used in Financing Activities	(19,615)	(7,918)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(784)	(2,015)
Net Change in Cash and Cash Equivalents	(10,087)	(15,994)
Cash and Cash Equivalents at Beginning of Period	52,362	15,994
Cash and Cash Equivalents at End of Period	$42,275	$--

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the condensed consolidated financial statements for the periods presented. The condensed consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 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 and six month periods ended June 30, 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Percentage-of-Completion Revenues	16.3%	17.3%	14.1%	16.6%

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

(in thousands)	June 30, 2013	December 31, 2012
Costs Incurred on Uncompleted Contracts	$324,743	$307,085
Less Billings to Date	(338,349)	(321,388)
Plus Estimated Earnings Recognized	2,570	1,762
	$(11,036)	$(12,541)

7

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

(in thousands)	June 30, 2013	December 31, 2012
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$5,122	$3,663
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(16,158)	(16,204)
	$(11,036)	$(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 $2.9 million in the three months ended June 30, 2012 and $0 in the three months ended June 30, 2013, and $8.7 million in the six months ended June 30, 2012 and $0.5 million in the six months ended June 30, 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 products sold by the Company 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 June 30, 2013 relates entirely to products that were produced by the Company's manufacturers of wind towers and waterfront equipment prior to the Company selling the assets of these companies 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:

(in thousands)	June 30, 2013	December 31, 2012
Accounts Receivable Retained by Customers	$7,844	$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.

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 June 30, 2013 and December 31, 2012:

June 30, 2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$1,180
Forward Gasoline Purchase Contracts		94	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,617	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,278	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	183		
Equity Securities - Nonqualified Retirement Savings Plan	130		
Total Assets	$423	$8,989	$1,180
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$--	$13,294
Total Liabilities	$--	$--	$13,294

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

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Forward Energy Contracts – Prices used for the fair valuation of these forward purchases and sales of electricity, which have illiquid trading points, are indexed to a price at an active market.

Forward Gasoline Purchase Contracts – These contracts are priced based on New York Mercantile Exchange (NYMEX) quoted prices for Reformulated Blendstock for Oxygenate Blending (RBOB) Gasoline contracts. Prices used for the fair valuation of these contracts are based on NYMEX daily reporting date quoted prices for RBOB contracts with the same settlement periods.

Corporate and U.S. Government Debt Securities Held by the Company's Captive Insurance Company – Fair values are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

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 above as of June 30, 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 $18.00 to $50.00 per megawatt-hour. The weighted average price was $37.30 per megawatt-hour.

In the table above, $436,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and $12,591,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of June 30, 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 purchased power 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 or six month periods ended June 30, 2013 and 2012.

The remaining $744,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and $703,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of June 30, 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. The related forward energy purchase and sales contracts are 100% offsetting in terms of volumes, delivery periods and delivery points. These contracts are scheduled for settlement in 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 table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the six-month periods ended June 30, 2013 and 2012:

(in thousands)	Six Months Ended June 30, 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	3,776	2,861
Changes in Fair Value of Contracts Entered into in Prior Periods	1,851	(5,046)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(12,155)	(18,069)
Net Increase in Value of Open Contracts Entered into in Current Period	41	--
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(12,114)	$(18,069)

10

Inventories
Inventories consist of the following:

(in thousands)	June 30, 2013	December 31, 2012
Finished Goods	$ 22,012	$ 21,893
Work in Process	9,739	8,800
Raw Material, Fuel and Supplies	41,660	38,643
Total Inventories	$ 73,411	$ 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) June 30, 2013
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 June 30, 2013 and December 31, 2012:

June 30, 2013 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,510	$ 12,301	15 – 25 years
Other Intangible Assets Including Contracts	825	410	415	5 – 30 years
Total	$ 17,636	$ 4,920	$ 12,716	
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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Amortization Expense – Intangible Assets	$244	$246	$488	$493

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

	As of June 30,	
(in thousands)	2013	2012
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions[1]	$ 14,935	$ 6,558

[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 June 30, 2013 and its maximum exposure to loss as a result of its involvement with CCMC as of June 30, 2013 totaled $9.4 million.

Reclassifications and Changes to Presentation

The Company's consolidated income statement and consolidated statement of cash flows for the three and six month periods ended June 30, 2012 reflect the reclassifications of the operating results and cash flows of discontinued operations as a result of the completion of the sale of the assets of the Company's wind tower manufacturer and discontinuance of wind tower production activities in November 2012 and the sale of the assets of the Company's waterfront equipment manufacturer on February 8, 2013. The reclassification had no impact on the Company's total consolidated net income or cash flows for the three or six months ended June 30, 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 June 30, 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 Midcontinent Independent System Operator, Inc. (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 provided technical and engineering services. OTESCO ceased operations in July 2013. OTESCO has not recorded any operating revenues, expenses or net income in 2013.

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.

13

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
United States of America	97.6 %	97.3 %	97.7 %	97.7 %
Mexico	1.2 %	1.0 %	1.2 %	0.9 %
Canada	1.1 %	1.5 %	1.0 %	1.3 %
All Other Countries (none greater than 0.07%)	0.1 %	0.2 %	0.1 %	0.1 %

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three and six months ended June 30, 2013 and 2012 and total assets by business segment as of June 30, 2013 and December 31, 2012 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Electric	$82,862	$78,963	$183,872	$168,966
Manufacturing	49,793	53,039	102,959	112,473
Construction	34,994	37,934	61,419	73,551
Plastics	44,761	41,490	82,161	76,365
Corporate Revenues and Intersegment Eliminations	(21)	(25)	(68)	(64)
Total	$212,389	$211,401	$430,343	$431,291

Interest Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Electric	$4,264	$4,762	$9,072	$9,613
Manufacturing	816	917	1,631	1,832

Construction	110	310	217	563
Plastics	256	346	504	692
Corporate and Intersegment Eliminations	1,431	2,137	2,433	4,366
Total	$6,877	$8,472	$13,857	$17,066

14

Income Taxes

(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Electric	$(817)	$(800)	$3,265	$822
Manufacturing	1,373	1,674	3,591	3,998
Construction	20	(1,164)	(703)	(3,940)
Plastics	2,627	2,722	5,230	4,897
Corporate	(1,109)	(1,915)	(3,403)	(4,792)
Total	$2,094	$517	$7,980	$985

Earnings (Loss) Available for Common Shares

(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Electric	$3,583	$5,191	$15,514	$16,207
Manufacturing	2,045	2,501	5,363	5,966
Construction	24	(1,756)	(1,068)	(5,927)
Plastics	3,925	4,067	7,812	7,320
Corporate	(2,073)	(3,286)	(5,396)	(6,858)
Discontinued Operations	197	(24,257)	326	(27,189)
Total	$7,701	$(17,540)	$22,551	$(10,481)

Identifiable Assets

(in thousands)	June 30, 2013	December 31, 2012
Electric	$ 1,229,185	$ 1,226,145
Manufacturing	118,411	114,933
Construction	52,519	50,696
Plastics	90,222	78,855
Corporate	100,000	112,616
Discontinued Operations	1,132	19,092
Total	$ 1,591,469	$ 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. In addition, a new standard established by the 2013 legislature requires 1.5% of total electric sales to be supplied by solar energy by the year 2020. OTP is currently evaluating the new legislation and potential options for meeting that standard. 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'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. 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. Because the request to extend the period of the new rate for 18 months was still under review, a supplemental filing was submitted on February 15, 2013, requesting that the current rate be retained until a majority of the remaining costs were recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the February 15, 2013 request on April 4, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. As of May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs. OTP has a regulatory asset of $0.1 million for renewable resource costs and returns eligible for recovery from Minnesota customers that had not been billed to Minnesota customers as of June 30, 2013 that will remain until OTP's 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 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. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The 2013 legislature passed legislation that also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. 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 then 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 the April 2012 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. The MNDOC filed comments on May 24, 2013 recommending removal of capitalized internal labor costs and costs in excess of planning estimates used in prior CON proceedings. OTP filed reply comments on June 27, 2013 disagreeing with the MNDOC's recommendations. OTP has a regulatory asset of $0.2 million for amounts eligible for recovery from Minnesota customers through the TCR rider that had not been billed to Minnesota customers as of June 30, 2013.

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, transitioned 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 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 recognized an additional $0.4 million of incentive related to 2011 and submitted its annual 2011 financial incentive filing request for $2.6 million. 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. 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 and an additional $0.1 million in 2013 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. The proposed implementation date for the surcharge of July 1, 2013 has been surpassed pending a decision which is now anticipated to be in the later part of 2013.

OTP has a regulatory asset of $6.1 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of June 30, 2013. OTP recognized revenue for Minnesota conservation costs and incentives earned totaling $1.7 million in the three month period ended June 30, 2013, compared with $1.5 million in the three month period ended June 30, 2012 and $3.3 million in the six month period ended June 30, 2013, compared with $3.2 million in the six month period ended June 30, 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. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013. On July 10, 2013, the NDPSC approved the rate implemented on April 1, 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 June 30, 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 $0.6 million 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. Updated rates were approved on April 23, 2013 and went into effect on May 1, 2013.

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.

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 initially 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. In addition, the Big Stone South – Brookings Multi-Value Project is also designated as a CapX2020 project.

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. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC's approval of the MVP cost allocation.

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.

18

The Big Stone South – Brookings MVP—This transmission line is planned at 345 kV and will extend 70 miles between a proposed substation near Big Stone City, South Dakota and the new Brookings County Substation near Brookings, South Dakota. OTP and Xcel Energy are joint owners of this project and Xcel Energy is the development manager. 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, expected to be in service in 2017, will use previously obtained Big Stone II transmission route permits and easements. 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 jointly submitted an application to the SDPUC for a route permit for the southern portion of the Big Stone South to Brookings line on June 3, 2013.

The Big Stone South – Ellendale MVP—This transmission line is a proposed 345 kV line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. 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. On May 31, 2013 OTP and MDU filed separate applications with the NDPSC for Certificates of Public Convenience and Necessity (CPCN) for the ten miles of the proposed line to be built in North Dakota. On July 10, 2013, the NDPSC set the notice period for the CPCN to August 19, 2013. Applications for route permits are expected to be filed with the SDPUC and NDPSC in the third quarter of 2013. If the proposed project receives all the necessary approvals, OTP anticipates the line will be placed in service in 2019.

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 an 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.

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 the 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 an Advanced Determination of Prudence (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). On May 24, 2013 legislation was enacted in Minnesota which allows OTP to file for an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment (including CWIP) at the level approved in the utility's last general rate case, unless a different return is determined by the MPUC to be in the public interest. OTP filed a petition requesting rider recovery on July 31, 2013.

On May 9, 2012 the NDPSC approved OTP's application for an ADP for anticipated AQCS costs attributable to serving OTP's North Dakota customers. On February 8, 2013, OTP filed a request with the NDPSC for an environmental rider to recover the revenue requirements 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 NDPSC will hold a hearing on September 16, 2013 to review the filing. An update of the estimated costs in the request for a rider was filed on May 8, 2013.

On March 30, 2012 OTP requested approval from the SDPUC for an environmental rider to recover costs associated with the AQCS. The proposed rider was 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. Instead of receiving rider recovery on the portion of AQCS construction costs assignable to OTP's South Dakota customers while the project is under construction, OTP will accrue an Allowance for Funds Used During Construction (AFUDC) on these costs and request recovery of, and a return on, the accumulated costs, including AFUDC, in a future rate filing in South Dakota.

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 in OTP's general rate case, 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 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 are included in the tracker account. The Minnesota Route Permit for these transmission facilities expired and subsequently OTP determined it was appropriate to treat the transmission projects as cancelled projects includable in the tracker account in the second quarter of 2013.

Approximately $0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP in the first quarter of 2013. The remaining transmission costs could not be used by other active transmission projects. Therefore, these costs, along with accumulated AFUDC, were transferred from CWIP to the Big Stone II Unrecovered Project Costs – Minnesota long-term regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP will not earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately $3.5 million was discounted to its present value of $2.8 million using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of $0.7 million related to the discount in accordance with ASC 980 - Regulated Operations, accounting requirements. The amount of the discount is expected to be recovered, along with the remaining balance of the Big Stone II Unrecovered Project Costs – Minnesota regulatory asset, over an anticipated 89-month recovery period beginning in May 2013 and ending in September 2020.

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. In the second quarter of 2013, OTP transferred the remaining North Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling $1.0 million from CWIP to the Big Stone II Unrecovered Project Costs – North Dakota current regulatory asset account. OTP filed a supplement to the NDPSC request on May 7, 2013 adding AFUDC costs, thus increasing the amount to be collected and the duration of the regulatory asset to be extended eight months. The May 7, 2013 supplemental request was approved by the NDPSC on July 30, 2013, which allows OTP to keep the existing Big Stone II rates in place to recover the remaining transmission costs plus accumulated AFUDC over an eight month period ending March 31, 2014.

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 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling $0.2 million from CWIP to the Big Stone II Unrecovered Project Costs – South Dakota long-term regulatory asset account.

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. 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 tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

	June 30, 2013			Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits1	$8,410	$105,334	$113,744	see note
Deferred Marked-to-Market Losses1	5,572	7,037	12,609	66 months
Conservation Improvement Program Costs and Incentives2	2,439	3,782	6,221	24 months
Big Stone II Unrecovered Project Costs – Minnesota1	541	4,182	4,723	87 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,386	4,386	asset lives
Debt Reacquisition Premiums1	351	2,417	2,768	231 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	676	1,442	2,118	30 months
Deferred Income Taxes1	--	1,777	1,777	asset lives
Big Stone II Unrecovered Project Costs – North Dakota1	1,069	--	1,069	9 months
Big Stone II Unrecovered Project Costs – South Dakota2	101	893	994	119 months
North Dakota Renewable Resource Rider Accrued Revenues2	451	227	678	21 months
Deferred Environmental Compliance Costs	419	--	419	12 months
Minnesota Transmission Rider Accrued Revenues2	161	--	161	12 months
Minnesota Renewable Resource Rider Accrued Revenues2	--	68	68	see note
Deferred Holding Company Formation Costs1	55	--	55	12 months
General Rate Case Recoverable Expenses – South Dakota1	43	--	43	7 months
North Dakota Transmission Rider Accrued Revenues2	25	--	25	12 months
Total Regulatory Assets	$20,313	$131,545	$151,858	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$67,112	$67,112	asset lives
Deferred Income Taxes	--	2,350	2,350	asset lives
Deferred Marked-to-Market Gains	19	436	455	62 months

Refundable Fuel Clause Adjustment Revenues	398	--	398	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	5	109	114	246 months
South Dakota – Nonasset-Based Margin Sharing Excess	57	--	57	6 months
Revenue for Rate Case expenses Subject to Refund – Minnesota	--	41	41	see note
South Dakota Transmission Rider Accrued Refund	36	--	36	12 months
Total Regulatory Liabilities	$515	$70,048	$70,563	
Net Regulatory Asset Position	$19,798	$61,497	$81,295	

1Costs subject to recovery without a rate of return.

2 Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

22

	December 31, 2012			Remaining
(in thousands)	Current	Long-Term	Total	Recovery/ Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits1	$8,411	$109,538	$117,949	see note
Deferred Marked-to-Market Losses1	7,949	10,050	17,999	72 months
Conservation Improvement Program Costs and Incentives2	3,707	2,560	6,267	18 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,137	4,137	asset lives
Debt Reacquisition Premiums1	268	1,978	2,246	237 months
Big Stone II Unrecovered Project Costs – Minnesota1	526	1,618	2,144	45 months
Recoverable Fuel and Purchased Power Costs1	1,737	--	1,737	12 months
Deferred Income Taxes1	--	1,691	1,691	asset lives
North Dakota Renewable Resource Rider Accrued Revenues2	532	1,087	1,619	15 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	--	1,352	1,352	see note
Minnesota Renewable Resource Rider Accrued Revenues2	915	--	915	5 months
Big Stone II Unrecovered Project Costs – North Dakota1	908	--	908	7 months
Big Stone II Unrecovered Project Costs – South Dakota2	100	711	811	97 months
General Rate Case Recoverable Expenses1	279	6	285	13 months
North Dakota Transmission Rider Accrued Revenues2	110	--	110	12 months
Deferred Holding Company Formation Costs1	55	27	82	18 months
South Dakota Transmission Rider Accrued Revenue2	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	

1Costs subject to recovery without a rate of return.
2 Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

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 June 30, 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.

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

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 231 months.

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 June 30, 2013 balance will be amortized on a straight-line basis over two consecutive 12-month periods beginning in January 2014.

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

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

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

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

The Minnesota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that have not been billed to Minnesota customers as of June 30, 2013.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of June 30, 2013. A supplemental filing was submitted to the MPUC on February 15, 2013, requesting that the then current MNRRA rate be retained until a majority of the remaining costs were 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 OTP’s next general rate case.

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

The North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve North Dakota customers net of transmission revenues that have not been billed to North Dakota customers as of June 30, 2013.

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

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

Revenue for Rate Case expenses Subject to Refund - Minnesota relate to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund.

The South Dakota Transmission Rider Accrued Refund relates 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 June 30, 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 June 30, 2013 OTP had recognized, on a pretax basis, $40,000 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 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 June 30, 2013 and December 31, 2012, and the change in the Company's consolidated balance sheet position from December 31, 2012 to June 30, 2013 and December 31, 2011 to June 30, 2012:

(in thousands)	June 30, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	$ 1,180	$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	5,572	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	7,037	10,050
Total Assets	13,789	18,501
Current Liability – Marked-to-Market Loss	(13,294)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(19)	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(436)	(210)
Total Liabilities	(13,749)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	$ 40	$ 49

(in thousands)	Year-to-Date June 30, 2013	Year-to-Date June 30, 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)	(700)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
	--	161

Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period				
Changes in Fair Value of Contracts Entered into in Current Period		40		(30)
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$	40	$	131

The $40,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2013 are expected to be realized on settlement as scheduled over the following period in the amount listed:

(in thousands)	3rd Qtr 2013	Total
Net Gain	$ 40	$ 40

25

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Net Gains (Losses) on Forward Electric Energy Contracts	$ 28	$ (50)	$ 254	$ 144

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

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of June 30, 2013 and December 31, 2012:

	June 30, 2013		December 31, 2012	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$1,290	3	$580	6
Net Credit Risk to Single Largest Counterparty	$850		$285	

OTP had a net credit risk exposure to three counterparties with investment grade credit ratings. OTP had no exposure at June 30, 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 June 30, 2013 and December 31, 2012 are indicated in the following table:

(in thousands)	June 30, 2013	December 31, 2012
Derivative assets subject to legally enforceable netting arrangements	$ 1,274	$ 638
Derivative liabilities subject to legally enforceable netting arrangements	(13,294)	(18,234)
Net balance subject to legally enforceable netting arrangements	$ (12,020)	$ (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 June 30, 2013 and December 31, 2012:

Current Liability – Marked-to-Market Loss (in thousands)	June 30, 2013	December 31, 2012
Loss Contracts Covered by Deposited Funds or Letters of Credit	$--	$2,176

Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	13,294	16,058
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$13,294	$18,234

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

Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	$13,294	$16,058
Offsetting Gains with Counterparties under Master Netting Agreements	(917)	(416)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$12,377	$15,642

26

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 June 30, 2013:

Common Shares Outstanding, December 31, 2012	36,168,368
Issuances:	
Stock Options Exercised	53,809
Vesting of Restricted Stock Units	17,435
Restricted Stock Issued to Employees	17,000
Restricted Stock Issued to Directors	16,000
Director's Compensation	4,535
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(7,184)
Forfeiture of Unvested Restricted Stock	(2,000)
Common Shares Outstanding, June 30, 2013	36,267,963

Earnings Per Share
The numerator used in the calculation of both basic and diluted earnings per common share is earnings available for common shares with no adjustments for the three and six month periods ended June 30, 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 and six month periods ended June 30, 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 three and six month periods ended June 30, 2013 and 2012:

Three Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2013	--	--
2012	92,497	$24.93 – $27.245

Six Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2013	--	--
2012	92,497	$24.93 – $27.245

27

7. Share-Based Payments

The Company has five share-based payment programs.

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.

As of June 30, 2013 the remaining unrecognized compensation expense related to stock-based compensation was approximately $6.3 million (before income taxes) which will be amortized over a weighted-average period of 2.4 years.

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

(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Employee Stock Purchase Plan (15% discount)	$ 42	$ 49	$ 59	$ 88
Restricted Stock Granted to Directors	162	138	369	274
Restricted Stock Granted to Employees	112	87	204	145
Restricted Stock Units Granted to Employees	79	51	154	105
Stock Performance Awards Granted to Executive Officers	703	293	1,801	293
Totals	$ 1,098	$ 618	$ 2,587	$ 905

28

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 June 30, 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 44.8% and 54.8%. OTP's equity to total capitalization ratio including short-term debt was 52.3% as of June 30, 2013. Total capitalization for OTP cannot currently exceed $874 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 $79.4 million. At June 30, 2013 OTP had commitments under contracts in connection with construction programs aggregating approximately $154.3 million. The increase in construction commitments from December 31, 2012 to June 30, 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
As of December 31, 2012 OTP had commitments for the purchase of capacity and energy requirements under agreements extending through 2032 totaling $170.1 million. In the second quarter of 2013, OTP entered into a 25-year agreement with Ashtabula Wind III, LLC for the purchase of wind generated electricity from the LLC's 39 wind turbines located in Barnes County, North Dakota. OTP is not required to take energy under this agreement until it receives an affirmative determination from the MPUC that OTP's execution of this agreement is reasonable, in the public interest, and that all costs incurred under this agreement to serve OTP's Minnesota customers are recoverable from OTP's retail customers in Minnesota. As of August 9, 2013 OTP had not received this affirmative determination. Therefore, OTP currently has no financial commitment related to this agreement.

As of December 31, 2012 OTP had contracts providing for the purchase and delivery of a significant portion of its then current coal requirements totaling $797.0 million. 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 and May of 2013, OTP entered into agreements for the purchase of additional coal to meet a portion of Big

Stone Plant's remaining coal requirements for 2013 and 2014. OTP's share of the additional commitments subsequent to June 30, 2013 total $2.5 million for 2013 and $3.2 million for 2014.

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 $2.9 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 June 30, 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 June 30, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on June 30, 2013	Restricted due to Outstanding Letters of Credit	Available on June 30, 2013	Available on December 31, 2012
Otter Tail Corporation Credit Agreement	$150,000	$ --	$ 680	$ 149,320	$ 149,267
OTP Credit Agreement	170,000	1,117	1,189	167,694	166,811
Total	$320,000	$ 1,117	$ 1,869	$ 317,014	$ 316,078

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. Those cumulative preferred shares 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 six-month period ending June 30, 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.

OTP plans to close on a private placement of $150 million of senior unsecured debt on August 14, 2013. On June 28, 2013 the issuance was priced as follows:

Principal Amount	Term	Rate
$60 million	15 years	4.68%
$90 million	30 years	5.47%

Proceeds from the issuance, scheduled to fund on February 27, 2014, will be used for OTP's planned construction program expenditures and to retire OTP's $40.9 million unsecured term loan due June 1, 2014. Therefore, the Term Loan remains classified as long-term debt on the Company's June 30, 2013 consolidated balance sheet.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2013 and December 31, 2012:

June 30, 2013 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$1,117	$--	$ --	$ 1,117
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 June 30, 2013	--		1,638	1,638
Total	$335,900		$ 101,638	$ 437,538
Less: Current Maturities	--		182	182
Unamortized Debt Discount	--		3	3
Total Long-Term Debt	$335,900		$ 101,453	$ 437,353
Total Short-Term and Long-Term Debt (with current maturities)	$337,017	$--	$ 101,635	$ 438,652

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

31

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 June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$1,418	$1,248	$2,836	$2,542
Interest Cost on Projected Benefit Obligation	3,036	3,125	6,072	6,233
Expected Return on Assets	(3,632)	(3,607)	(7,264)	(7,215)
Amortization of Prior-Service Cost:				
From Regulatory Asset	83	100	166	199
From Other Comprehensive Income1	2	2	4	5
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,663	1,255	3,326	2,454
From Other Comprehensive Income1	45	34	90	66
Net Periodic Pension Cost	$2,615	$2,157	$5,230	$4,284

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 June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$13	$12	$26	$23
Interest Cost on Projected Benefit Obligation	352	369	704	739
Amortization of Prior-Service Cost:				
From Regulatory Asset	5	6	10	11
From Other Comprehensive Income1	13	13	26	26
Amortization of Net Actuarial Loss:				
From Regulatory Asset	52	38	104	77
From Other Comprehensive Income2	78	43	156	86
Net Periodic Pension Cost	$513	$481	$1,026	$962
1Amortization of Prior Service Costs from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	$5	$5	$10	$10
Other Nonelectric Expenses	8	8	16	16
2Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:				

Electric Operation and Maintenance Expenses	$48	$36	$96	$72
Other Nonelectric Expenses	30	7	60	14

Postretirement Benefits—Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired OTP and corporate employees, net of the effect of the Medicare Part D Subsidy:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$441	$374	$882	$772
Interest Cost on Projected Benefit Obligation	610	630	1,220	1,287
Amortization of Transition Obligation:				
From Regulatory Asset	--	182	--	364
From Other Comprehensive Income1	--	5	--	10
Amortization of Prior-Service Cost:				
From Regulatory Asset	51	52	102	103
From Other Comprehensive Income1	1	1	2	2
Amortization of Net Actuarial Loss:				
From Regulatory Asset	248	135	496	321
From Other Comprehensive Income1	6	4	12	9
Net Periodic Postretirement Benefit Cost	$1,357	$1,383	$2,714	$2,868
Effect of Medicare Part D Subsidy	$(564)	$(533)	$(1,128)	$(1,020)

1 Corporate cost included in Other Nonelectric Expenses.

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 1.25%.

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.

	June 30, 2013		December 31, 2012	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 42,275	$ 42,275	$ 52,362	$ 52,362
Short-Term Debt	(1,117)	(1,117)	--	--
Long-Term Debt including Current Maturities	(437,535)	(482,670)	(421,856)	(491,244)

33

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 and six month periods ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Income Before Income Taxes – Continuing Operations	$9,598	$7,418	$30,718	$18,061
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	3,743	2,893	11,980	7,044
Increases (Decreases) in Tax from:				
Federal Production Tax Credits (PTCs)	(1,841)	(1,831)	(3,430)	(3,818)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	--	--	--	(676)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(216)	(149)	(439)	(371)
Corporate Owned Life Insurance	(92)	(13)	(394)	(385)
Medicare Part D Subsidy	4	(194)	--	(391)
Employee Stock Ownership Plan Dividend Deduction	(188)	(191)	(378)	(381)
Deferred Tax Asset Reduction - North Dakota due to Tax Rate Decrease	365	--	365	--
Other Items - Net	319	2	276	(37)
Income Tax Expense – Continuing Operations	$2,094	$517	$7,980	$985
Effective Income Tax Rate – Continuing Operations	21.8%	7.0%	26.0%	5.5%

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

(in thousands)	2013
Balance on January 1	$ 4,436
Increases Related to Tax Positions for Prior Years	67
Uncertain Positions Adjusted During Year	(511)
Balance on June 30	$ 3,992

The balance of unrecognized tax benefits as of June 30, 2013 would not reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2013 is not expected to change significantly within the next six months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. No interest is accrued on tax uncertainties as of June 30, 2013.

17. Discontinued Operations

On February 8, 2013 the Company completed the sale of substantially all the assets of its waterfront equipment manufacturing company, formerly included in the Company's Manufacturing segment, for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013. On November 30, 2012 the Company completed the sale of the assets of its wind tower manufacturing company 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 and six-month periods ended June 30, 2013 and 2012:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Operating Revenues	$ 7	$ 72,308	$ 2,016	$ 146,359
Operating Expenses	(161)	65,650	2,546	139,095
Asset Impairment Charge	--	45,573	--	45,573
Operating Income (Loss)	168	(38,915)	(530)	(38,309)
Interest Charges	--	5	--	174
Other Income	160	97	572	230
Income Tax Expense (Benefit)	131	(15,021)	(74)	(14,608)
Net Income (Loss) from Operations	197	(23,802)	116	(23,645)
(Loss) Gain on Disposition Before Taxes	--	(490)	216	(3,713)
Income Tax (Benefit) Expense on Disposition	--	(35)	6	(169)
Net (Loss) Gain on Disposition	--	(455)	210	(3,544)
Net Income (Loss)	$ 197	$ (24,257)	$ 326	$ (27,189)

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of June 30, 2013 and December 31, 2012:

(in thousands)	June 30, 2013	December 31, 2012
Current Assets	$ 1,019	$ 18,487
Investments	--	85
Net Plant	113	520
Assets of Discontinued Operations	$ 1,132	$ 19,092
Current Liabilities	$ 5,332	$ 11,156
Liabilities of Discontinued Operations	$ 5,332	$ 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	(582)
Decrease in Warranty Estimates for Prior Years	(663)

Warranty Reserve Balance, June 30, 2013	$	3,902

The warranty reserve balance as of December 31, 2012 and June 30, 2013 relates entirely to products produced by the Company's former wind tower and waterfront equipment manufacturing companies. Expenses associated with remediation activities of these companies could be substantial. Although the assets of these companies have been sold and their 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 they produced prior to the sales of these companies. For 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. For example, 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.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and six month periods ended June 30, 2013 and 2012, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2013 and our business outlook for the remainder of 2013.

Comparison of the Three Months Ended June 30, 2013 and 2012

Consolidated operating revenues were $212.4 million for the three months ended June 30, 2013 compared with $211.4 million for the three months ended June 30, 2012. Operating income was $15.8 million for the three months ended June 30, 2013 compared with $15.2 million for the three months ended June 30, 2012. The Company recorded diluted earnings per share from continuing operations of $0.21 for the three months ended June 30, 2013 compared to $0.19 for the three months ended June 30, 2012 and total diluted earnings per share of $0.21 for the three months ended June 30, 2013 compared to ($0.48) for the three months ended June 30, 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 June 30, 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)	June 30, 2013	June 30, 2012
Operating Revenues:		
Electric	$ 24	$ 23
Nonelectric	(3)	2
Cost of Goods Sold	1	9
Other Nonelectric Expenses	20	16

Electric

(in thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Change	% Change
Retail Sales Revenues	$ 72,263	$ 68,719	$ 3,544	5.2
Wholesale Revenues – Company Generation	3,432	2,028	1,404	69.2
Net Revenue – Energy Trading Activity	596	561	35	6.2
Other Revenues	6,571	7,655	(1,084)	(14.2)
Total Operating Revenues	$ 82,862	$ 78,963	$ 3,899	4.9
Production Fuel	15,603	12,455	3,148	25.3
Purchased Power – System Use	11,245	12,328	(1,083)	(8.8)
Other Operation and Maintenance Expenses	35,805	32,407	3,398	10.5
Depreciation and Amortization	10,672	10,447	225	2.2
Property Taxes	3,009	2,670	339	12.7
Operating Income	$ 6,528	$ 8,656	$ (2,128)	(24.6)

Three Months Ended

	June 30,			%
Electric kwh Sales (in thousands)	2013	2012	Change	Change
Retail kilowatt-hour (kwh) Sales	962,006	907,529	54,477	6.0
Wholesale kwh Sales – Company Generation	110,912	71,364	39,548	55.4
Wholesale kwh Sales – Purchased Power Resold	36,065	58,632	(22,567)	(38.5)

36

The $3.5 million increase in retail sales revenues reflects the following:

a $1.7 million increase in Transmission Cost Recovery Rider revenues as a result of increased investment in transmission assets,

a $1.1 million increase in revenue related to a 6.0% increase in retail kwh sales resulting, in part, from colder spring weather in 2013 compared with 2012, as heating-degree days were up 70.3% between the quarters, and

a $0.9 million increase in revenue related to the recovery of increased fuel and purchased power costs driven by increased kwh generation to meet higher retail kwh sales demand and by higher purchased power prices, tempered by lower prices for fuel per kwh generated and a reduction in kwhs purchased,

offset by:

a $0.2 million decrease in Renewable Resource Cost Recovery Rider revenue in Minnesota.

Wholesale electric revenues from company-owned generation increased $1.4 million as a result of a 55.4% increase in wholesale kwh sales combined with an 8.9% increase in wholesale electric prices driven by increased market demand due, in part, to the colder spring in 2013. Otter Tail Power Company (OTP) also had more generation resources available to meet wholesale demand in the second quarter of 2013.

Other electric operating revenues decreased $1.1 million as a result of:

a $0.9 million reduction in estimated revenue from shared use of transmission facilities with another regional transmission provider under an integrated transmission service agreement, and

a $0.3 million decrease in Midcontinent Independent System Operator, Inc. (MISO) transmission tariff revenues due to implementation of a revised and lower tariff in October 2012,

offset by:

a $0.2 million increase in revenue from steam sales to an ethanol producer adjacent to the Big Stone Plant site, due to the customer burning less natural gas to meet its steam requirements in 2013 in response to higher natural gas prices.

Fuel costs increased $3.1 million as a result of a 35.3% increase in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 7.4% decrease in the cost of fuel per kwh generated. Generation levels increased as a result of greater plant availability and in response to higher demand due to colder weather in the second quarter of 2013 compared with the second quarter of 2012. The average cost of fuel per kwh of generation decreased mainly as a result of a 17.8% decrease in the cost of fuel per kwh generated at OTP's Big Stone Plant combined with a 14.0% increase in kwhs generated at that plant and a 75.6% increase in kwhs generated at Coyote Station, OTP's lowest fuel-cost plant, which was shut down for seven weeks of scheduled maintenance in the second quarter of 2012.

The cost of purchased power for retail sales decreased $1.1 million as a result of a 23.7% decrease in kwhs purchased, partially offset by a 19.5% increase in the cost per kwh purchased. The decrease in kwhs purchased was directly related to an increase in the availability of owned generation to serve retail load.

Electric operating and maintenance expenses increased $3.4 million mainly due to the following:

a $1.3 million increase in general and administrative expenses, mostly related to an increase in corporate costs allocated to the Electric segment due, in part, to changes in corporate cost allocation factors resulting from the corporation's recent divestitures,

a $1.2 million increase in labor and benefit expenses, mainly due to increases in pension and retirement health benefit costs resulting from reductions in discount rates related to projected benefit obligations,

a $1.0 million increase in MISO transmission tariff charges related to increasing investments in regional CapX2020 and MISO-designated Multi-Value (MVP) transmission projects, and

- a $0.7 million discount recorded on the Minnesota jurisdictional share of abandoned Big Stone II project transmission assets that were transferred from construction work in progress (CWIP) to a regulatory asset account for future recovery as the initial investment was deemed prudent but potential future uses for the assets did not materialize,

offset by:

- a $0.8 million reduction in external service costs, which were higher in the second quarter of 2012 as a result of the seven-week scheduled maintenance outage at Coyote Station.

The $0.3 million increase in property tax expense is related to higher property value assessments in Minnesota and South Dakota.

Manufacturing

(in thousands)	Three Months Ended June 30, 2013	2012	Change	% Change
Operating Revenues	$ 49,793	$ 53,039	$ (3,246)	(6.1)
Cost of Goods Sold	37,447	40,186	(2,739)	(6.8)
Operating Expenses	5,321	4,773	548	11.5
Depreciation and Amortization	2,793	3,064	(271)	(8.8)
Operating Income	$ 4,232	$ 5,016	$ (784)	(15.6)

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 $3.0 million as a result of lower sales volume mainly due to reduced demand from customers in end markets serving the construction and energy industries.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased by $0.2 million as a result of a decrease in sales of packaging products.

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

Cost of goods sold at BTD decreased $2.6 million, mainly as a result of reductions in material costs related to decreased sales volume.

Cost of goods sold at T.O. Plastics decreased $0.2 million as a result of reductions in raw material and direct labor costs and also due to continuing productivity improvements.

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

Operating expenses at BTD increased $0.6 million between the quarters.

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

Construction

(in thousands)	Three Months Ended June 30, 2013	2012	Change	% Change
Operating Revenues	$ 34,994	$ 37,934	$ (2,940)	(7.8)
Cost of Goods Sold	31,601	36,992	(5,391)	(14.6)
Operating Expenses	2,748	3,030	(282)	(9.3)
Depreciation and Amortization	496	470	26	5.5
Operating Income (Loss)	$ 149	$ (2,558)	$ 2,707	105.8

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, increased $0.6 million between the quarters as a result of earning higher margins on contracts in progress in the second quarter of 2013 compared with the second quarter of 2012.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, decreased $3.5 million due, in part, to a colder and wetter spring in 2013 that delayed the start of many construction projects relative to the early start to construction that was facilitated by extremely mild weather in the second quarter of 2012. Aevenia's second quarter 2012 results also included revenues of $2.1 million from Moorhead Electric, Inc. (MEI), 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 $3.3 million between the quarters, which is mainly reflective of cost overruns incurred on certain large projects under construction in 2012.

Cost of goods sold at Aevenia decreased $2.1 million between the quarters, mainly as a result of the sale of MEI in October 2012. MEI's cost of goods sold totaled $1.8 million in the second quarter of 2012.

Aevenia's operating expenses decreased $0.2 million in the second quarter of 2013 compared to the second quarter of 2012 as a result of the sale of MEI.

Plastics

(in thousands)	Three Months Ended June 30, 2013	2012	Change	% Change
Operating Revenues	$ 44,761	$ 41,490	$ 3,271	7.9
Cost of Goods Sold	34,890	31,257	3,633	11.6
Operating Expenses	2,241	2,328	(87)	(3.7)
Depreciation and Amortization	822	785	37	4.7
Operating Income	$ 6,808	$ 7,120	$ (312)	(4.4)

The increase in Plastics segment revenue is the result of a 10.2% increase in pounds of polyvinyl chloride (PVC) pipe sold, partially offset by a 2.1% decrease in the price per pound of pipe sold. Sales volume increased as construction and housing markets continued to improve 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 colder and wetter spring in 2013. The increase in costs of goods sold was mostly due to the increase in pounds of pipe sold, but was also due to a 1.3% increase in the cost per pound of PVC pipe sold related to higher raw material costs.

Corporate

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

(in thousands)	Three Months Ended June 30, 2013	2012	Change	% Change
Operating Expenses	$ 1,886	$ 2,864	$ (978)	(34.1)
Depreciation and Amortization	52	124	(72)	(58.1)

The decrease in Corporate operating expense between the quarters includes a $0.7 million decrease in insurance costs and a $1.0 million increase in Corporate expenses allocated to our Electric segment, offset by a $0.8 million increase in benefit costs related to 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.

Interest Charges

The $1.6 million decrease in interest charges in the second quarter of 2013 compared with the second quarter of 2012, includes $1.1 million related to the early redemption, in July 2012, of our $50 million, 8.89% senior unsecured note and $0.2 million related to OTP's debt refinancing on March 1, 2013, when it borrowed $40.9 million under an unsecured term loan due June 1, 2014, bearing interest at LIBOR plus 0.875% and utilized a portion of the proceeds to redeem its $25.1 million in outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds. Interest charges also decreased as a result of a $6.1 million decrease in average short-term debt outstanding between the quarters.

Income Taxes – Continuing Operations

Income taxes - continuing operations increased $1.6 million in the second quarter of 2013 compared with the second 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 June 30, 2013 and 2012:

(in thousands)	Three Months Ended June 30, 2013	2012
Income Before Income Taxes – Continuing Operations	$ 9,598	$ 7,418
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	3,743	2,893
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,841)	(1,831)
Deferred Tax Asset Reduction due to Tax Rate Decrease in North Dakota	365	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(216)	(149)
Employee Stock Ownership Plan Dividend Deduction	(188)	(191)
Corporate Owned Life Insurance	(92)	(13)

Medicare Part D Subsidy		4			(194	)
Other Items – Net		319			2	
Income Tax Expense – Continuing Operations	$	2,094		$	517	
Effective Income Tax Rate – Continuing Operations		21.8	%		7.0	%

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 completed the sale of substantially all the assets of our waterfront equipment business for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013. On November 30, 2012 we completed the sale of the assets of our wind tower manufacturing business. On February 29, 2012 we sold DMS Health Technologies, Inc. (DMS) and in 2011 we sold E.W. Wylie Corporation (Wylie), our trucking business. The financial position of our waterfront equipment and wind tower manufacturing companies and the results of operations and cash flows of our waterfront equipment and wind tower manufacturing companies, DMS and Wylie 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 June 30, 2013 and 2012:

	For the Three Months Ended June 30,	
(in thousands)	2013	2012
Operating Revenues	$ 7	$ 72,308
Operating Expenses	(161)	65,650
Asset Impairment Charge	--	45,573
Operating Income (Loss)	168	(38,915)
Interest Charges	--	5
Other Income	160	97
Income Tax Expense (Benefit)	131	(15,021)
Net Income (Loss) from Operations	197	(23,802)
Loss on Disposition Before Taxes	--	(490)
Income Tax Benefit on Disposition	--	(35)
Net Loss on Disposition	--	(455)
Net Income (Loss)	$ 197	$ (24,257)

Comparison of the Six Months Ended June 30, 2013 and 2012

Consolidated operating revenues were $430.3 million for the six months ended June 30, 2013 compared with $431.3 million for the six months ended June 30, 2012. Operating income was $43.0 million for the six months ended June 30, 2013 compared with $33.5 million for the six months ended June 30, 2012. The Company recorded diluted earnings per share from continuing operations of $0.61 for the six months ended June 30, 2013 compared to $0.46 for the six months ended June 30, 2012 and total diluted earnings per share of $0.62 for the six months ended June 30, 2013 compared to ($0.29) for the six months ended June 30, 2012.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six month periods ended June 30, 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)	June 30, 2013	June 30, 2012
Operating Revenues:		
Electric	$ 58	$ 57
Nonelectric	10	7
Cost of Goods Sold	14	20

Other Nonelectric Expenses	54	44

41

Electric

(in thousands)	Six Months Ended June 30, 2013	2012	Change	% Change
Retail Sales Revenues	$ 164,586	$ 150,141	$ 14,445	9.6
Wholesale Revenues – Company Generation	5,065	4,107	958	23.3
Net Revenue – Energy Trading Activity	941	973	(32)	(3.3)
Other Revenues	13,280	13,745	(465)	(3.4)
Total Operating Revenues	$ 183,872	$ 168,966	$ 14,906	8.8
Production Fuel	33,556	27,879	5,677	20.4
Purchased Power – System Use	27,884	26,486	1,398	5.3
Other Operation and Maintenance Expenses	68,252	62,420	5,832	9.3
Asset Impairment Charge	--	432	(432)	(100.0)
Depreciation and Amortization	21,303	20,847	456	2.2
Property Taxes	5,925	5,287	638	12.1
Operating Income	$ 26,952	$ 25,615	$ 1,337	5.2

Electric kwh Sales (in thousands)	Six Months Ended June 30, 2013	2012	Change	% Change
Retail kwh Sales	2,272,318	2,112,134	160,184	7.6
Wholesale kwh Sales – Company Generation	175,257	166,755	8,502	5.1
Wholesale kwh Sales – Purchased Power Resold	49,854	65,032	(15,178)	(23.3)

The $14.4 million increase in retail sales revenues reflects the following:

a $6.8 million increase in revenue related to the recovery of increased fuel and purchased power costs driven by increased kwh generation to meet higher retail kwh sales demand and by higher purchased power prices, tempered by a 3.6% reduction in kwhs purchased,

a $5.0 million increase in revenue related to a 7.6% increase in retail kwh sales resulting from significantly colder weather in the first six months of 2013 compared with the first six months of 2012, as evidenced by a 41.0% increase in heating-degree days between the periods,

a $2.2 million increase in Transmission Cost Recovery Rider revenues as a result of increased investment in transmission assets, and

$0.4 million in revenue related to deferred recovery of amounts invested in plant for environmental improvements.

Wholesale electric revenues from company-owned generation increased $1.0 million as a result of a 5.1% increase in wholesale kwh sales combined with a 17.3% increase in wholesale electric prices driven by increased market demand due, in part, to the colder spring in 2013.

Other electric operating revenues decreased $0.5 million as a result of:

a $0.9 million reduction in estimated revenue from shared use of transmission facilities with other regional transmission providers,

offset by:

a $0.4 million increase in revenue from steam sales to an ethanol producer adjacent to OTP’s Big Stone Plant site, due to the customer burning less natural gas to meet its steam requirements in 2013 in response to rising natural gas prices.

Fuel costs increased $5.7 million due to a 21.5% increase in kwhs generated from OTP’s steam-powered and combustion turbine generators as a result of greater plant availability in 2013 and higher system demand driven by more seasonal weather in the first six months of 2013 compared to the first six months of 2012. The increase in fuel costs related to the increase in kwhs generated was slightly offset by a 0.9% decrease in the cost of fuel per kwh generated.

The cost of purchased power for retail sales increased $1.4 million as a result of a 9.2% increase in the cost per kwh purchased offset by a 3.6% decrease in kwhs purchased. The increase in purchased power prices was driven by an increase in demand due to more seasonal weather in the first six months of 2013 compared to milder weather in the first six months of 2012.

Electric operating and maintenance expenses increased $5.8 million mainly due to the following:
- a $2.1 million increase in MISO transmission tariff charges related to increasing investments in regional CapX2020 and MISO-designated MVPs,
- a $2.0 million increase in labor and benefit expenses due to increases in pension and retirement health benefit costs resulting from reductions in discount rates related to projected benefit obligations, wage increases, a reduction in capitalized labor in 2013 compared with 2012 and an increase in accrued performance incentives,
- a $1.8 million increase in general and administrative expenses, mostly related to an increase in corporate costs allocated to the Electric segment due, in part, to changes in corporate cost allocation factors resulting from the corporation's recent divestitures, and
- a $0.7 million discount on OTP's investment in the Minnesota jurisdictional share of abandoned transmission plant that was transferred from CWIP to a regulatory asset account for future recovery, as the initial investment was deemed prudent but potential future uses for the assets did not materialize,

offset by:
- a $0.9 million reduction in external service, material and operating supply costs, which were higher in 2012 primarily as a result of the seven-week scheduled maintenance outage at Coyote Station.

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 ceased operations in July 2013. OTESCO has not recorded any operating revenues, expenses or net income in 2013.

The $0.6 million increase in property tax expense is related to higher property value assessments in Minnesota and South Dakota.

Manufacturing

	Six Months Ended June 30,			
(in thousands)	2013	2012	Change	% Change
Operating Revenues	$ 102,959	$ 112,473	$ (9,514)	(8.5)
Cost of Goods Sold	76,773	84,853	(8,080)	(9.5)
Operating Expenses	9,819	9,819	--	--
Depreciation and Amortization	5,786	6,082	(296)	(4.9)
Operating Income	$ 10,581	$ 11,719	$ (1,138)	(9.7)

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

Revenues at BTD decreased $9.1 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 decreased by $0.4 million as a result of a decrease in sales of packaging products.

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

Cost of goods sold at BTD decreased $7.4 million, mainly as a result of reductions in material costs related to decreased sales volume.

Cost of goods sold at T.O. Plastics decreased $0.7 million as a result of reductions in raw material and labor costs and also due to continuing productivity improvements.

Construction

(in thousands)	Six Months Ended June 30, 2013	2012	Change	% Change
Operating Revenues	$ 61,419	$ 73,551	$ (12,132)	(16.5)
Cost of Goods Sold	55,877	75,685	(19,808)	(26.2)
Operating Expenses	6,134	6,310	(176)	(2.8)
Depreciation and Amortization	958	904	54	6.0
Operating Loss	$ (1,550)	$ (9,348)	$ 7,798	83.4

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

Revenues at Foley decreased $4.7 million, mainly as a result of a reduction in work volume between the periods as several large projects were near completion in 2012.

Revenues at Aevenia decreased $7.4 million as a result of a decrease in construction activity due, in part, to a harsher winter and colder and wetter spring 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 six months of 2012. Aevenia's revenues in the first six months of 2012 also included $3.3 million from MEI, 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 $14.5 million as a result of the reduction in work volume and a $6.0 million reduction in cost overruns between the periods on major projects nearing completion during the periods.

Cost of goods sold at Aevenia decreased $5.3 million between the periods as a result of a decrease in construction activity due, in part, to a harsher winter and colder and wetter spring 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 six months of 2012. MEI's cost of goods sold totaled $2.8 million in the first six months of 2012.

Plastics

(in thousands)	Six Months Ended June 30, 2013	2012	Change	% Change
Operating Revenues	$ 82,161	$ 76,365	$ 5,796	7.6
Cost of Goods Sold	63,363	58,204	5,159	8.9
Operating Expenses	3,677	3,691	(14)	(0.4)
Depreciation and Amortization	1,596	1,598	(2)	(0.1)
Operating Income	$ 13,525	$ 12,872	$ 653	5.1

The increase in Plastics segment revenue is the result of an 8.6% increase in pounds of PVC pipe sold, partially offset by a 0.9% decrease in the price per pound of pipe sold. Sales volume increased as construction and housing markets continued to improve 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 harsher winter weather and a colder and wetter spring in 2013. The increase in costs of goods sold was mostly due to the increase in pounds of pipe sold, but also reflects a 0.3% increase in the cost per pound of pipe sold.

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.

	Six Months Ended June 30,			%
(in thousands)	2013	2012	Change	Change
Operating Expenses	$ 6,378	$ 7,105	$ (727)	(10.2)
Depreciation and Amortization	112	252	(140)	(55.6)

The decrease in Corporate operating expense reflects a $1.0 million decrease in various corporate administrative and general expenses and a $1.3 million increase in Corporate expenses allocated to our Electric segment, partially offset by a $1.6 million increase in 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.

Interest Charges

The $3.2 million decrease in interest charges in the first six months of 2013 compared with the first six months of 2012, is mostly due to the early redemption, in July 2012, of our $50 million, 8.89% senior unsecured note, which resulted in a $2.2 million decrease in interest charges between periods. Interest charges decreased $0.3 million as a result of OTP's debt refinancing on March 1, 2013, when it borrowed $40.9 million under an unsecured term loan due June 1, 2014, bearing interest at LIBOR plus 0.875% and used a portion of the proceeds to redeem its $25.1 million in outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds. A $0.1 million increase in capitalized interest expense at OTP also contributed to the decrease in interest charges. Interest charges also decreased as a result of a decrease in average short-term debt outstanding between the periods.

Income Taxes – Continuing Operations

Income taxes - continuing operations increased $7.0 million in the first six months of 2013 compared with the first six months 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 six month periods ended June 30, 2013 and 2012:

	Six Months Ended June 30,	
(in thousands)	2013	2012
Income Before Income Taxes – Continuing Operations	$30,718	$18,061
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	11,980	7,044
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(3,430)	(3,818)
Reversal of Accrued Interest on Removal of Cost Capitalization Audit Issue	--	(676)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(439)	(371)
Corporate Owned Life Insurance	(394)	(385)

Medicare Part D Subsidy	--		(391	)
Employee Stock Ownership Plan Dividend Deduction	(378	)	(381	)
Deferred Tax Asset Reduction - North Dakota due to Tax Rate Decrease	365		--	
Other Items - Net	276		(37	)
Income Tax Expense – Continuing Operations	$7,980		$985	
Effective Income Tax Rate – Continuing Operations	26.0	%	5.5	%

45

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 our water front equipment business for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013. In the first quarter of 2013, we paid approximately $0.8 million in expenses related to the sale of our waterfront equipment business and we also paid a $1.7 million working capital settlement to the purchaser of DMS, which was sold on February 29, 2012. On November 30, 2012 we completed the sale of the assets of our wind tower manufacturing business and in 2011 we sold E.W. Wylie Corporation (Wylie), our trucking business. The financial position of our waterfront equipment and wind tower manufacturing companies and the results of operations and cash flows of our waterfront equipment and wind tower manufacturing companies, DMS and Wylie are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the six month periods ended June 30, 2013 and 2012:

	For the Six Months Ended June 30,	
(in thousands)	2013	2012
Operating Revenues	$ 2,016	$ 146,359
Operating Expenses	2,546	139,095
Asset Impairment Charge	--	45,573
Operating Loss	(530)	(38,309)
Interest Charges	--	174
Other Income	572	230
Income Tax Benefit	(74)	(14,608)
Net Income (Loss) from Operations	116	(23,645)
Gain (Loss) on Disposition Before Taxes	216	(3,713)
Income Tax Expense (Benefit) on Disposition	6	(169)
Net Gain (Loss) on Disposition	210	(3,544)
Net Income (Loss)	$ 326	$ (27,189)

FINANCIAL POSITION

The following table presents the status of our lines of credit as of June 30, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on June 30, 2013	Restricted due to Outstanding Letters of Credit	Available on June 30, 2013	Available on December 31, 2012
Otter Tail Corporation Credit Agreement	$150,000	$--	$ 680	$149,320	$149,267
OTP Credit Agreement	170,000	1,117	1,189	167,694	166,811
Total	$320,000	$1,117	$ 1,869	$317,014	$316,078

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.

46

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 statements 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 $48.8 million for the six months ended June 30, 2013 compared with $45.6 million for the six months ended June 30, 2012. Cash provided by operating activities from continuing operations reflects a $5.7 million increase in net income from continuing operations offset by a $1.8 million increase in cash used for working capital items in the first six months of 2013 compared to the first six months of 2012.

Net cash used in investing activities of continuing operations was $49.6 million for the six months ended June 30, 2013 compared to $63.0 million for the six months ended June 30, 2012 due to a $12.7 million decrease in cash used for capital expenditures at the electric utility between the periods. Although the level of construction activity at OTP was similar between the periods, OTP’s $57.0 million in capital expenditures in the first six months of 2012 included a $13.8 million reduction in construction-related accounts payable. Net proceeds from the sale of discontinued operations of $12.8 million in the first six months of 2013 reflect $14.5 million in net proceeds from the sale of the assets of our waterfront equipment manufacturing business 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 $24.3 million in the first six months of 2012, which were used to pay down short-term borrowings and for other corporate purposes, reflect proceeds, net of selling costs, of $24.0 million from the sale of DMS and $0.3 million from the January 2012 sale of the assets of Aviva Sports, Inc., a wholly owned subsidiary of our waterfront equipment manufacturing company. Net cash used in investing activities of discontinued operations of $12.8 million in the first six months of 2012 reflects cash used by DMS to purchase assets held under operating leases.

Net cash used in financing activities of continuing operations of $19.6 million reflects $2.6 million in proceeds from short term borrowings and the issuance of common stock, offset by $22.1 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 four new transmission line projects.

In May 2013, we 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 OTP 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, changes were made to revise the anticipated timing of a portion of Big Stone area transmission project capital costs from 2016 and 2017 into 2018 and 2019.

The following table shows our revised 2013 through 2017 anticipated capital expenditures and electric utility average rate base:

(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 $87 million as of June 30, 2013. Our obligations for the purchase of coal have increased by $3 million for 2013 and $3 million for 2014 related to agreements entered into in February and May of

2013 for the purchase of additional coal to meet a portion of Big Stone Plant's remaining coal requirements for 2013 and 2014. 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 $54 million for 2013 and $43 million for 2014 and 2015 and decreased by $22 million for 2016 mainly for contracts and the acceleration of the timing of committed expenditures 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 Corporation 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 six month period ending June 30, 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.

OTP plans to close on a private placement of $150 million of senior unsecured debt on August 14, 2013. On June 28, 2013 the issuance was priced as follows:

Principal Amount	Term	Rate
$60 million	15 years	4.68%
$90 million	30 years	5.47%

Proceeds from the issuance, scheduled to fund on February 27, 2014, will be used for OTP's planned construction program expenditures and to retire OTP's $40.9 million unsecured 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 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 June 30, 2013 we were in compliance with the financial statement covenants 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 June 30, 2013 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 3.47 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 June 30, 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 3.49 to 1.00.

As of June 30, 2013 our interest-bearing debt to total capitalization was 0.46 to 1.00 on a fully consolidated basis and 0.48 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $8.6 million, but our line of credit borrowing limits are only restricted by $1.9 million of the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2013 BUSINESS OUTLOOK

We are narrowing our consolidated earnings per share from continuing operations guidance for 2013 to be in the range of $1.30 to $1.50 from our previous guidance 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.

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	$1.02	$1.07	$1.02	$1.06
Manufacturing	$0.28	$0.33	$0.27	$0.31
Construction	$0.06	$0.11	$0.01	$0.05
Plastics	$0.25	$0.30	$0.31	$0.35
Corporate	($0.31)	($0.26)	($0.31)	($0.27)
Total – Continuing Operations	$1.30	$1.55	$1.30	$1.50

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

We are narrowing our guidance for 2013 for our Electric segment based on increases in benefit and administrative costs.

We are also narrowing our guidance and reducing the low end of the range for 2013 for our Manufacturing segment 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 $76 million for 2013 compared with $71 million one year ago.

We are reducing our 2013 guidance for our Construction segment due to disappointing results at Aevenia during the first six months of 2013. Segment net income is still 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 expect Foley to be profitable in 2013. Backlog in place for the construction businesses is $74 million for 2013 compared with $73 million one year ago.

We are increasing our 2013 guidance for our Plastics segment based on the strength of its performance in the first half of 2013.

Corporate general and administrative costs are expected to be in line with previous 2013 guidance.

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 June 30, 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 (CO2) 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 June 30, 2013 we had exposure to market risk associated with interest rates because we had $1.1 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 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 June 30, 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 June 30, 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 June 30, 2013 OTP had recognized, on a pretax basis, $40,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase contracts that are marked to market as of June 30, 2013, are 100% offset by forward energy sales contracts in terms of volumes, delivery periods and points of delivery.

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.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on our consolidated balance sheets as of June 30, 2013 and December 31, 2012, and the change in our consolidated balance sheet position from December 31, 2012 to June 30, 2013 and December 31, 2011 to June 30, 2012:

(in thousands)	June 30, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	$ 1,180	$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	5,572	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	7,037	10,050
Total Assets	13,789	18,501
Current Liability – Marked-to-Market Loss	(13,294)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(19)	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(436)	(210)
Total Liabilities	(13,749)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	$ 40	$ 49

(in thousands)	Year-to-Date June 30, 2013	Year-to-Date June 30, 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)	(700)
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	--	161
Changes in Fair Value of Contracts Entered into in Current Period	40	(30)
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 40	$ 131

The $40,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2013 are expected to be realized on settlement as scheduled over the following period in the amount listed:

(in thousands)	3rd Qtr 2013	Total
Net Gain	$ 40	$ 40

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2013	2012	2013	2012
Net Gains (Losses) on Forward Electric Energy Contracts	$ 28	$ (50)	$ 254	$ 144

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of June 30, 2013 was $850,000. As of June 30, 2013 OTP had a net credit risk exposure of $1,290,000 from three counterparties with investment grade credit ratings. OTP had no exposure at June 30, 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 $1,290,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after June 30, 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 June 30, 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 June 30, 2013.

During the fiscal quarter ended June 30, 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for incentive awards in April 2013 under the Company's 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2013	7,126	$ 31.030
May 2013	58	$ 31.034
June 2013	--	--
Total	7,184	

Item 6. Exhibits

10.1	Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

*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: August 9, 2013

57

EXHIBIT INDEX

Exhibit Number	Description
10.1	Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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