Otter Tail Corp
Form 10-Q
November 12, 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 September 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:

October 31, 2013 – 36,270,696 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$59,117	$52,362
Accounts Receivable:		
Trade—Net	98,164	91,170
Other	15,215	7,684
Inventories	72,658	69,336
Deferred Income Taxes	19,696	30,964
Unbilled Revenues	12,304	15,701
Costs and Estimated Earnings in Excess of Billings	4,858	3,663
Regulatory Assets	17,754	25,499
Other	10,167	8,161
Assets of Discontinued Operations	432	19,092
Total Current Assets	310,365	323,632
Investments	9,325	9,471
Other Assets	27,696	26,222
Goodwill	38,971	38,971
Other Intangibles—Net	13,572	14,305
Deferred Debits		
Unamortized Debt Expense	4,341	5,529
Regulatory Assets	131,921	134,755
Total Deferred Debits	136,262	140,284
Plant		
Electric Plant in Service	1,438,543	1,423,303
Nonelectric Operations	194,636	186,094
Construction Work in Progress	159,202	77,890
Total Gross Plant	1,792,381	1,687,287
Less Accumulated Depreciation and Amortization	670,298	637,835
Net Plant	1,122,083	1,049,452
Total Assets	$1,658,274	$1,602,337

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	September 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$40,335	$--
Current Maturities of Long-Term Debt	185	176
Accounts Payable	109,604	88,406
Accrued Salaries and Wages	18,122	20,571
Billings In Excess Of Costs and Estimated Earnings	16,202	16,204
Accrued Taxes	10,609	12,047
Derivative Liabilities	12,707	18,234
Other Accrued Liabilities	7,734	6,334
Liabilities of Discontinued Operations	4,080	11,156
Total Current Liabilities	219,578	173,128
Pensions Benefit Liability	109,139	116,541
Other Postretirement Benefits Liability	59,477	58,883
Other Noncurrent Liabilities	25,746	22,244
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	177,248	171,787
Deferred Tax Credits	28,791	31,299
Regulatory Liabilities	70,446	68,835
Other	643	466
Total Deferred Credits	277,128	272,387
Capitalization		
Long-Term Debt, Net of Current Maturities	437,306	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—36,269,363 Shares; 2012—36,168,368 Shares	181,347	180,842

Premium on Common Shares	255,167	253,296
Retained Earnings	97,569	92,221
Accumulated Other Comprehensive Loss	(4,183)	(4,385)
Total Common Equity	529,900	521,974
Total Capitalization	967,206	959,154
Total Liabilities and Equity	$1,658,274	$1,602,337

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating Revenues				
Electric	$86,275	$88,550	$270,089	$257,458
Nonelectric	143,493	126,766	390,022	389,149
Total Operating Revenues	229,768	215,316	660,111	646,607
Operating Expenses				
Production Fuel – Electric	18,785	20,622	52,341	48,501
Purchased Power - Electric System Use	8,691	8,138	36,575	34,624
Electric Operation and Maintenance Expenses	30,626	28,717	98,878	91,137
Asset Impairment Charge - Electric	--	--	--	432
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	115,475	103,152	311,474	321,874
Other Nonelectric Expenses	12,857	12,424	38,811	39,305
Depreciation and Amortization	15,039	15,057	44,794	44,740
Property Taxes - Electric	3,163	2,833	9,088	8,120
Total Operating Expenses	204,636	190,943	591,961	588,733
Operating Income	25,132	24,373	68,150	57,874
Interest Charges	6,574	7,904	20,431	24,970
Loss on Early Retirement of Debt	--	13,106	--	13,106
Other Income	1,401	653	2,958	2,279
Income from Continuing Operations Before Income Taxes	19,959	4,016	50,677	22,077
Income Tax Expense (Benefit) – Continuing Operations	5,133	(785)	13,113	200
Net Income from Continuing Operations	14,826	4,801	37,564	21,877
Discontinued Operations				
Income (Loss) - net of Income Tax Expense (Benefit) of $39, ($75), ($35) and $3,431 for the respective periods	312	(2,928)	428	886
Impairment Loss - net of Income Tax (Benefit) of $0, $0, $0 and ($18,114) for the respective periods	--	--	--	(27,459)
Gain (Loss) on Disposition - net of Income Tax Expense (Benefit) of $0, $0, $6, and ($169) for the respective periods	--	--	210	(3,544)
Net Income (Loss) from Discontinued Operations	312	(2,928)	638	(30,117)
Net Income (Loss)	15,138	1,873	38,202	(8,240)
Preferred Dividend Requirements and Other Adjustments	--	183	513	551
Earnings (Loss) Available for Common Shares	$15,138	$1,690	$37,689	$(8,791)
Average Number of Common Shares Outstanding—Basic	36,179,507	36,061,002	36,141,664	36,043,276
Average Number of Common Shares Outstanding—Diluted	36,381,900	36,252,765	36,344,063	36,235,039
Basic Earnings (Loss) Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.41	$0.13	$1.02	$0.59

Discontinued Operations	0.01	(0.08)	0.02	(0.83)
	$0.42	$0.05	$1.04	$(0.24)
Diluted Earnings (Loss) Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.41	$0.13	$1.02	$0.59
Discontinued Operations	0.01	(0.08)	0.02	(0.83)
	$0.42	$0.05	$1.04	$(0.24)
Dividends Declared Per Common Share	$0.2975	$0.2975	$0.8925	$0.8925

See accompanying notes to consolidated financial statements.

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

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net Income (Loss)	$15,138	$1,873	$38,202	$(8,240)
Other Comprehensive 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)	--
Gains (Losses) Arising During Period	19	72	(66)	180
Income Tax (Expense) Benefit	(7)	(29)	32	(72)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	12	43	(59)	108
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 12)	145	101	436	305
Income Tax Expense	(58)	(41)	(175)	(122)
Pension and Postretirement Benefit Plans – net-of-tax	87	60	261	183
Total Other Comprehensive Income	99	103	202	291
Total Comprehensive Income (Loss)	$15,237	$1,976	$38,404	$(7,949)

See accompanying notes to consolidated financial statements.

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

(in thousands)	Nine Months Ended September 30, 2013	2012
Cash Flows from Operating Activities		
Net Income (Loss)	$38,202	$(8,240)
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	(428)	26,573
Depreciation and Amortization	44,794	44,740
Asset Impairment Charge	--	432
Premium Paid for Early Retirement of Long-Term Debt	--	12,500
Deferred Tax Credits	(1,422)	(1,568)
Deferred Income Taxes	15,215	8,320
Change in Deferred Debits and Other Assets	9,817	16,493
Discretionary Contribution to Pension Plan	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	7,318	8,029
Allowance for Equity-Other Funds Used During Construction	(1,462)	(518)
Change in Derivatives Net of Regulatory Deferral	120	752
Stock Compensation Expense—Equity Awards	1,116	930
Other—Net	813	4,257
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(9,775)	(16,536)
Change in Inventories	(3,323)	864
Change in Other Current Assets	(252)	6,268
Change in Payables and Other Current Liabilities	4,170	15,021
Change in Interest and Income Taxes Receivable/Payable	1,156	(11,203)
Net Cash Provided by Continuing Operations	95,849	100,658
Net Cash (Used in) Provided by Discontinued Operations	(2,499)	48,724
Net Cash Provided by Operating Activities	93,350	149,382
Cash Flows from Investing Activities		
Capital Expenditures	(109,690)	(93,653)
Net Proceeds from Disposal of Noncurrent Assets	2,615	2,380
Net Increase in Other Investments	(680)	(1,393)
Net Cash Used in Investing Activities - Continuing Operations	(107,755)	(92,666)
Net Proceeds from Sale of Discontinued Operations	12,842	24,278
Net Cash Provided by (Used in) Investing Activities - Discontinued Operations	505	(11,494)
Net Cash Used in Investing Activities	(94,408)	(79,882)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	--	3,535
Net Short-Term Borrowings	40,335	12,417
Proceeds from Issuance of Common Stock	1,496	--
Common Stock Issuance Expenses	--	(181)
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	(126)	(14)
Payments for Retirement of Long-Term Debt	(25,266)	(50,183)
Premium Paid for Early Retirement of Long-Term Debt	--	(12,500)
Dividends Paid and Other Distributions	(33,027)	(33,033)
Net Cash Provided by (Used in) Financing Activities - Continuing Operations	8,589	(80,069)
Net Cash Used in Financing Activities - Discontinued Operations	--	(3,410)
Net Cash Provided by (Used in) Financing Activities	8,589	(83,479)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(776)	(2,015)
Net Change in Cash and Cash Equivalents	6,755	(15,994)
Cash and Cash Equivalents at Beginning of Period	52,362	15,994
Cash and Cash Equivalents at End of Period	$59,117	$--

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the condensed consolidated financial statements for the periods presented. The condensed consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes 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 nine month periods ended September 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) Topic 815, Derivatives and Hedging (ASC 815). 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Percentage-of-Completion Revenues	20.6 %	17.1 %	16.4 %	16.8 %

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

(in thousands)	September 30, 2013	December 31, 2012
Costs Incurred on Uncompleted Contracts	$341,649	$307,085
Less Billings to Date	(358,026)	(321,388)
Plus Estimated Earnings Recognized	5,033	1,762
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$(11,344)	$(12,541)

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

(in thousands)	September 30, 2013	December 31, 2012
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$4,858	$3,663
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(16,202)	(16,204)
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$(11,344)	$(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 $0.1 million in the three months ended September 30, 2013 and $1.7 million in the three months ended September 30, 2012, and $0.6 million in the nine months ended September 30, 2013 and $10.4 million in the nine months ended September 30, 2012.

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 September 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)	September 30, 2013	December 31, 2012
Accounts Receivable Retained by Customers	$6,989	$12,227

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Fair Value Measurements
The Company follows ASC Topic 820, Fair Value Measurements and Disclosures (ASC 820), 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 (NYMEX).

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 September 30, 2013 and December 31, 2012:

September 30, 2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$316
Forward Gasoline Purchase Contracts		66	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,608	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,278	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	722		
Equity Securities - Nonqualified Retirement Savings Plan	130		
Total Assets	$962	$8,952	$316
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$--	$12,707
Total Liabilities	$--	$--	$12,707

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 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 September 30, 2013 and December 31, 2012, are based on prices indexed to observable prices at an active trading hub. The Level 3 forward electric price inputs ranged from $6.95 per megawatt-hour under the active trading hub price to $2.45 per megawatt-hour over the active trading hub price. The weighted average price was $36.55 per megawatt-hour.

In the table above, the fair values for the Level 3 forward energy contracts as of September 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 nine month periods ended September 30, 2013 and 2012.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the nine-month periods ended September 30, 2013 and 2012:

	Nine Months Ended September 30,	
(in thousands)	2013	2012
Forward Energy Contracts - Fair Values Beginning of Period	$(17,782)	$--
Transfers into Level 3 from Level 2	--	(15,884)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	5,066	3,771
Changes in Fair Value of Contracts Entered into in Prior Periods	325	(4,517)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(12,391)	(16,630)
Net Increase in Value of Open Contracts Entered into in Current Period	--	22

Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(12,391)	$(16,608)

Inventories

Inventories consist of the following:

(in thousands)	September 30, 2013	December 31, 2012
Finished Goods	$ 19,682	$ 21,893
Work in Process	10,636	8,800
Raw Material, Fuel and Supplies	42,340	38,643
Total Inventories	$ 72,658	$ 69,336

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Goodwill

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) September 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 September 30, 2013 and December 31, 2012:

September 30, 2013 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,722	$ 12,089	15 – 25 years
Other Intangible Assets Including Contracts	825	442	383	5 – 30 years
Total	$ 17,636	$ 5,164	$ 12,472	
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 September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Amortization Expense – Intangible Assets	$245	$244	$733	$737

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

(in thousands)	2013	2014	2015	2016	2017
	$977	$977	$977	$945	$849

Estimated Amortization Expense – Intangible Assets

Supplemental Disclosures of Cash Flow Information

	As of September 30,	
(in thousands)	2013	2012
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions1	$ 25,133	$ 5,979
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions2	$ 5,172	$ --

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

2Amounts are deducted from cash used for capital expenditures in subsequent periods when cash is received.

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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 September 30, 2013 is $9.8 million. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC could be as high as $9.8 million as of September 30, 2013.

Reclassifications and Changes to Presentation

The Company's consolidated income statement and consolidated statement of cash flows for the three and nine month periods ended September 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 reclassifications had no impact on the Company's total consolidated net income or cash flows for the three or nine months ended September 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 (ASU 2011-11), 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 (ASU 2011-13), 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 September 30, 2013. The amounts of accumulated other comprehensive losses associated with the Company's pension and other post-retirement benefit programs that are being amortized and recognized as operating expenses and the income statement line item affected by the expense are disclosed 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 included 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.

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
United States of America	97.7 %	97.7 %	97.7 %	97.7 %
Mexico	1.5 %	1.1 %	1.3 %	1.0 %
Canada	0.7 %	1.1 %	0.9 %	1.2 %
All Other Countries (none greater than 0.08%)	0.1 %	0.1 %	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 nine months ended September 30, 2013 and 2012 and total assets by business segment as of September 30, 2013 and December 31, 2012 are presented in the following tables:

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Electric	$86,283	$88,564	$270,155	$257,530
Manufacturing	49,323	46,618	152,282	159,091
Construction	47,509	37,931	108,928	111,482
Plastics	46,659	42,217	128,820	118,582
Intersegment Eliminations	(6)	(14)	(74)	(78)
Total	$229,768	$215,316	$660,111	$646,607

Interest Charges

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Electric	$3,960	$4,880	$13,032	$14,493
Manufacturing	816	891	2,447	2,723
Construction	128	305	345	868
Plastics	249	342	753	1,034
Corporate and Intersegment Eliminations	1,421	1,486	3,854	5,852
Total	$6,574	$7,904	$20,431	$24,970

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012

Electric	$2,565	$2,995	$5,830	$3,817
Manufacturing	1,124	1,288	4,715	5,286
Construction	1,193	(879)	490	(4,819)
Plastics	2,278	2,216	7,508	7,113
Corporate	(2,027)	(6,405)	(5,430)	(11,197)
Total	$5,133	$(785)	$13,113	$200

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Earnings (Loss) Available for Common Shares

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Electric	$8,787	$10,206	$24,301	$26,413
Manufacturing	2,970	1,914	8,333	7,880
Construction	1,784	(1,325)	716	(7,252)
Plastics	3,403	3,309	11,215	10,629
Corporate	(2,118)	(9,486)	(7,514)	(16,344)
Discontinued Operations	312	(2,928)	638	(30,117)
Total	$15,138	$1,690	$37,689	$(8,791)

Identifiable Assets

(in thousands)	September 30, 2013	December 31, 2012
Electric	$ 1,280,682	$ 1,226,145
Manufacturing	122,942	114,933
Construction	59,904	50,696
Plastics	83,254	78,855
Corporate	111,060	112,616
Discontinued Operations	432	19,092
Total	$ 1,658,274	$ 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 September 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.

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. On March 26, 2012 the MPUC approved OTP's request for an update to the TCR rider, effective 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 February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery. A determination of eligibility for inclusion of the remaining nine projects is still pending. 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 Minnesota Department of Commerce (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. Both parties have filed additional comments supportive of their positions. OTP had a regulatory liability of $0.1 million as of September 30, 2013 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, 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.

On January 11, 2012 the MPUC approved 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 October 10, 2013 the MPUC approved OTP's 2012 financial incentive request for $2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 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 September 30, 2013. OTP recognized MNCIP-related revenues totaling $1.5 million in each of the three month periods ended September 30, 2013 and September 30, 2012, and $4.8 million in each of the nine month periods ended September 30, 2013 and September 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 $1.2 million for amounts eligible for recovery through the NDRRA rider that had not been billed to North Dakota customers as of September 30, 2013.

Transmission Cost Recovery Rider—OTP's initial North Dakota TCR rider went 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. OTP filed its annual update to the North Dakota TCR rider rate on August 30, 2013 with a proposed implementation date of January 1, 2014. OTP had a regulatory liability of $0.1 million as of September 30, 2013 for amounts billed to North Dakota customers that are subject to refund through the North Dakota TCR rider.

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. OTP filed its annual update to the South Dakota TCR rider rate on August 30, 2013 with a proposed implementation date of January 1, 2014.

Federal

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

Effective January 1, 2010, the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). OTP was also authorized by the FERC to recover in OTP's formula rate: (1) 100% of prudently incurred Construction Work in Progress (CWIP) in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional Capacity Expansion 2020 (CapX2020) transmission projects in which OTP is an investor, discussed in more detail below.

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 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. On October 7, 2013 certain parties submitted a Writ of Certiorari to the U.S. Supreme Court appealing the Seventh Circuit decision.

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.

The Big Stone South – Brookings MVP—This transmission line is planned at 345 kiloVolt (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 August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for the ten miles of the proposed line to be built in North Dakota. A joint route permit application was filed by OTP and MDU on August 23, 2013 with the SDPUC. OTP and MDU jointly filed an Application for a Certificate of Corridor and Compatibility along with an application for a route permit with the NDPSC on October 18, 2013. If the proposed project receives all the necessary approvals, OTP anticipates the line will be placed in service in 2019.

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

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.

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, with comments received by the Minnesota Chamber of Commerce and the MNDOC on September 26, 2013 and September 30, 2013. OTP filed reply comments agreeing with the MNDOC and Minnesota Chamber of Commerce recommendations and supplying additional detail requested by the MNDOC on October 10, 2013. The MNDOC filed a response to OTP's reply comments on October 21, 2013 supporting the filing and requesting approval.

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 beginning January 1, 2013 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. An update of the estimated costs in the request for a rider was filed on May 8, 2013. The NDPSC held a hearing on September 16, 2013 to review OTP's filing request for an environmental rider.

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 Topic 980 - Regulated Operations (ASC 980), 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. 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:

	September 30, 2013			Remaining Recovery/ Refund
(in thousands)	Current	Long-Term	Total	Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits1	$ 8,410	$ 103,232	$ 111,642	see note
Deferred Marked-to-Market Losses1	4,363	8,344	12,707	63 months
Conservation Improvement Program Costs and Incentives2	1,821	4,332	6,153	21 months
Big Stone II Unrecovered Project Costs – Minnesota1	550	4,075	4,625	84 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,515	4,515	asset lives
Debt Reacquisition Premiums1	351	2,329	2,680	228 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	1,014	1,473	2,487	27 months
Deferred Income Taxes1	--	1,820	1,820	asset lives
North Dakota Renewable Resource Rider Accrued Revenues2	313	864	1,177	18 months
Big Stone II Unrecovered Project Costs – South Dakota2	100	869	969	116 months
Big Stone II Unrecovered Project Costs – North Dakota1	763	--	763	6 months
Minnesota Renewable Resource Rider Accrued Revenues2	--	68	68	see note
Deferred Holding Company Formation Costs1	41	--	41	9 months
General Rate Case Recoverable Expenses – South Dakota1	24	--	24	4 months
South Dakota Transmission Rider Accrued Revenues2	4	--	4	12 months
Total Regulatory Assets	$ 17,754	$ 131,921	$ 149,675	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 67,610	$ 67,610	asset lives

Deferred Income Taxes		--		2,248		2,248	asset lives
Refundable Fuel Clause Adjustment Revenues		555		--		555	12 months
Deferred Marked-to-Market Gains		--		316		316	59 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota		--		165		165	see note
Deferred Gain on Sale of Utility Property – Minnesota Portion		6		107		113	243 months
North Dakota Transmission Rider Accrued Refund		75		--		75	12 months
Minnesota Transmission Rider Accrued Refund		54		--		54	12 months
South Dakota – Nonasset-Based Margin Sharing Excess		44		--		44	3 months
Total Regulatory Liabilities	$	734	$	70,446	$	71,180	
Net Regulatory Asset Position	$	17,020	$	61,475	$	78,495	

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

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(in thousands)	December 31, 2012 Current		Long-Term		Total	Remaining Recovery/ Refund Period
Regulatory Assets:						
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement 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
		6	112		118	252 months

Deferred Gain on Sale of Utility Property – Minnesota Portion							
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.
2Amount 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 Topic 715, Compensation—Retirement Benefits, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of September 30, 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 228 months.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes 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 September 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.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of September 30, 2013.

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.

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.

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 September 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 South Dakota Transmission Rider Accrued Revenues relate to revenues billed for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers net of transmission revenues that have not been billed to South Dakota customers as of September 30, 2013.

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

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 North Dakota Transmission Rider Accrued Refund relates to revenues earned on qualifying transmission system facilities and operating costs incurred to serve North Dakota customers net of transmission revenues that are refundable to North Dakota customers as of September 30, 2013.

The Minnesota Transmission Rider Accrued Refund relates to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that are refundable to Minnesota customers as of September 30, 2013.

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

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 September 30, 2013 OTP had no unrealized mark-to-market gains or losses in its income statement related to forward contracts for the purchase and sale of electricity. 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.

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

(in thousands)	September 30, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	$ 316	$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	4,363	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	8,344	10,050
Total Assets	13,023	18,501
Current Liability – Marked-to-Market Loss	(12,707)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	--	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(316)	(210)
Total Liabilities	(13,023)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	$ --	$ 49

(in thousands)	Year-to-Date September 30, 2013	Year-to-Date September 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)	(781)

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		--		80
Changes in Fair Value of Contracts Entered into in Current Period		--		(121)
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$	--	$	(41)

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 September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Net Gains (Losses) on Forward Electric Energy Contracts	$ 1	$ (274)	$ 255	$ (130)

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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 September 30, 2013 and December 31, 2012:

	September 30, 2013		December 31, 2012	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$335	2	$580	6
Net Credit Risk to Single Largest Counterparty	$321		$285	

OTP had a net credit risk exposure to two counterparties with investment grade credit ratings. OTP had no exposure at September 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 on forward contracts for the purchase of gasoline scheduled for settlement subsequent to September 30, 2013. 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 September 30, 2013 and December 31, 2012 are indicated in the following table:

(in thousands)	September 30, 2013	December 31, 2012
Derivative assets subject to legally enforceable netting arrangements	$ 382	$ 638
Derivative liabilities subject to legally enforceable netting arrangements	(12,707)	(18,234)
Net balance subject to legally enforceable netting arrangements	$ (12,325)	$ (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 September 30, 2013 and December 31, 2012:

Current Liability – Marked-to-Market Loss (in thousands)	September 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 Grade1	12,707	16,058
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$ 12,707	$ 18,234
1Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.		
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	$ 12,707	$ 16,058
Offsetting Gains with Counterparties under Master Netting Agreements	(316)	(416)

Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 12,391	$ 15,642

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6. Reconciliation of Common Shareholders' Equity, Common Shares and Earnings Per Share

Reconciliation of Common Shareholders' Equity

(in thousands)	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, December 31, 2012	$180,842	$253,296	$92,221	$ (4,385)	$521,974
Common Stock Issuances, Net of Expenses	551	1,848			2,399
Common Stock Retirements and Forfeitures	(46)	(177)			(223)
Net Income			38,202		38,202
Other Comprehensive Income				202	202
Tax Benefit – Stock Compensation		59			59
Employee Stock Incentive Plan Expense		313			313
Premium on Purchase of Stock for Employee Purchase Plan		(258)			(258)
Cumulative Preferred Dividends			(427)		(427)
Preferred Stock Issuance Expenses Transferred to Retained Earnings on Redemption of Preferred Shares		86	(86)		--
Common Dividends			(32,341)		(32,341)
Balance, September 30, 2013	$181,347	$255,167	$97,569	$ (4,183)	$529,900

Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2012 through September 30, 2013:

Common Shares Outstanding, December 31, 2012	36,168,368
Issuances:	
Stock Options Exercised	55,109
Vesting of Restricted Stock Units	17,535
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, September 30, 2013	36,269,363

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 nine month periods ended September 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 nine month periods ended September 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 nine month periods ended September 30, 2013 and 2012:

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

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 (the Stock Incentive Plan):

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 Topic 718, Compensation—Stock Compensation, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

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

As of September 30, 2013 the remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted-average period of 2.1 years.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Employee Stock Purchase Plan (15% discount)	$ 39	$ 31	$ 98	$ 119
Restricted Stock Granted to Directors	119	139	488	413
Restricted Stock Granted to Employees	111	87	315	232
Restricted Stock Units Granted to Employees	61	60	215	165
Stock Performance Awards Granted to Executive Officers	347	146	2,148	439
Totals	$ 677	$ 463	$ 3,264	$ 1,368

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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 September 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 49.5% as of September 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 September 30, 2013 OTP had commitments under contracts in connection with construction programs aggregating approximately $127.5 million. The increase in construction commitments from December 31, 2012 to September 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 power purchase agreement (PPA) 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. At its regular agenda meeting on August 22, 2013 the MPUC provided an affirmative determination that OTP's execution of this agreement is reasonable, in the public interest, and that costs incurred under this agreement to serve OTP's Minnesota customers will be recoverable. On October 1, 2013 OTP began accepting delivery of energy under the PPA. In September of 2013, OTP entered into an agreement with Great River Energy for the purchase of 25 megawatts (MW) of capacity from June 1, 2017 through May 31, 2019 and 50 MW of capacity from June 1, 2019 through May 31, 2021 to meet OTP's future capacity requirements. OTP's commitments under the Ashtabula Wind III, LLC PPA and the Great River Energy capacity purchase agreement have increased OTP's total estimated commitments under capacity and energy purchase agreements by $193.4 million.

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, May and September 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. In September of 2013, OTP entered into an agreement for the purchase of additional coal to meet a portion of Hoot Lake Plant's coal requirements for the remainder of 2013 and 2015. OTP's share of the additional commitments subsequent to September 30, 2013 total $3.9 million for 2013, $3.2 million for 2014 and $4.2 million for 2015.

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 $2.0 million. Additionally, the Company may become subject to significant claims of which its management is unaware, or the claims of which its management is aware, 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 September 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 September 30, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on September 30, 2013	Restricted due to Outstanding Letters of Credit	Available on September 30, 2013	Available on December 31, 2012
Otter Tail Corporation Credit Agreement	$150,000	$ --	$ 680	$ 149,320	$ 149,267
OTP Credit Agreement	170,000	40,335	1,189	128,476	166,811
Total	$320,000	$ 40,335	$ 1,869	$ 277,796	$ 316,078

On October 29, 2013 both the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were amended to extend the expiration dates by one year from October 29, 2017 to October 29, 2018.

Long-Term Debt Issuances, 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 originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015. Borrowings under the Loan Agreement bear interest at LIBOR plus 0.875%. 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 nine-month period ending September 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.

On August 14, 2013, OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP has agreed to issue to the purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP’s 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the 2029 Notes) and $90 million aggregate principal amount of OTP’s 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the 2044 Notes and, together with the 2029 Notes, the Notes). The Notes are expected to be issued on February 27, 2014, subject to the satisfaction of certain customary conditions to closing.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (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, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the 2029 Notes then outstanding on or after November 27, 2028 or (ii) all of the 2044 Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states the Company must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP that will be effective on issuance of the Notes. 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. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants. Specifically, OTP may not permit its Interest-bearing Debt (as defined in the 2013 Note Purchase Agreement) to exceed 60% of Total Capitalization (as defined in the 2013 Note Purchase Agreement), determined as of the end of each fiscal quarter. OTP is also restricted from allowing its Priority Indebtedness (as defined in the 2013 Note Purchase Agreement) to exceed 20% of Total Capitalization, also determined as of the end of each fiscal quarter. The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

OTP intends to use a portion of the proceeds of the Notes to retire early the Term Loan, due January 15, 2015. The remaining proceeds of the Notes will be used to repay short-term debt of OTP, to pay fees and expenses related to the issuance of the Notes and for other general corporate purposes, including planned construction program expenditures.

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

September 30, 2013 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$40,335	$--	$ --	$ 40,335
Long-Term Debt:				
Unsecured Term Loan - LIBOR plus 0.875%, due January 15, 2015	$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 September 30, 2013	--		1,594	1,594
Total	$335,900		$ 101,594	$ 437,494
Less: Current Maturities	--		185	185
Unamortized Debt Discount	--		3	3
Total Long-Term Debt	$335,900		$ 101,406	$ 437,306
Total Short-Term and Long-Term Debt (with current maturities)	$376,235	$--	$ 101,591	$ 477,826

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

12. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$ 1,359	$ 1,271	$ 4,195	$ 3,813
Interest Cost on Projected Benefit Obligation	3,021	3,116	9,093	9,349
Expected Return on Assets	(3,627)	(3,608)	(10,891)	(10,823)
Amortization of Prior-Service Cost:				
From Regulatory Asset	84	100	250	299
From Other Comprehensive Income1	3	3	7	8
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,624	1,229	4,950	3,683

From Other Comprehensive Income1	42	31	132	97
Net Periodic Pension Cost	$ 2,506	$ 2,142	$ 7,736	$ 6,426

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 September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$ 12	$ 11	$ 38	$ 34
Interest Cost on Projected Benefit Obligation	352	370	1,056	1,109
Amortization of Prior-Service Cost:				
From Regulatory Asset	6	5	16	16
From Other Comprehensive Income1	13	13	39	39
Amortization of Net Actuarial Loss:				
From Regulatory Asset	52	39	156	116
From Other Comprehensive Income2	79	43	235	129
Net Periodic Pension Cost	$ 514	$ 481	$ 1,540	$ 1,443
1Amortization of Prior Service Costs from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	$ 5	$ 5	$ 15	$ 15
Other Nonelectric Expenses	8	8	24	24
2Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	$ 49	$ 36	$ 145	$ 108
Other Nonelectric Expenses	30	7	90	21

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 September 30,		Nine Months Ended September 30,	
(in thousands)	2013	2012	2013	2012
Service Cost—Benefit Earned During the Period	$ 184	$ 386	$ 1,066	$ 1,158
Interest Cost on Projected Benefit Obligation	318	644	1,538	1,931
Amortization of Transition Obligation:				
From Regulatory Asset	--	182	--	546
From Other Comprehensive Income1	--	5	--	15
Amortization of Prior-Service Cost:				
From Regulatory Asset	52	51	154	154
From Other Comprehensive Income1	2	2	4	4
Amortization of Net Actuarial Loss:				
From Regulatory Asset	(478)	160	18	481
From Other Comprehensive Income1	(12)	4	--	13
Net Periodic Postretirement Benefit Cost	$ 66	$ 1,434	$ 2,780	$ 4,302
Effect of Medicare Part D Subsidy	$ (227)	$ (509)	$ (1,355)	$ (1,529)

1Corporate cost included in Other Nonelectric Expenses.

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13. Fair Value of Financial Instruments

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

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

Short-Term Debt—The carrying amount approximates fair value because the debt obligation is short-term and the balance outstanding related to the OTP Credit Agreement is subject to a variable interest rate that approximates current market rates (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.

	September 30, 2013		December 31, 2012	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 59,117	$ 59,117		