Otter Tail Corp
Form 10-Q
August 11, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2014

OR

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

Commission file number 0-53713

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

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

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

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

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

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

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

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

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

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

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

July 31, 2014 – 36,649,018 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$1,150
Accounts Receivable:		
Trade—Net	101,088	83,572
Other	11,531	9,790
Inventories	82,698	72,681
Deferred Income Taxes	43,342	35,452
Unbilled Revenues	16,222	18,157
Costs and Estimated Earnings in Excess of Billings	5,505	4,063
Regulatory Assets	18,423	17,940
Other	13,528	7,747
Assets of Discontinued Operations	10	38
Total Current Assets	292,347	250,590
Investments	8,875	9,362
Other Assets	30,056	28,834
Goodwill	38,808	38,971
Other Intangibles—Net	12,839	13,328
Deferred Debits		
Unamortized Debt Expense	4,330	4,188
Regulatory Assets	77,168	83,730
Total Deferred Debits	81,498	87,918
Plant		
Electric Plant in Service	1,507,065	1,460,884
Nonelectric Operations	195,302	194,872
Construction Work in Progress	210,960	187,461
Total Gross Plant	1,913,327	1,843,217
Less Accumulated Depreciation and Amortization	695,276	676,201
Net Plant	1,218,051	1,167,016
Total Assets	$1,682,474	$1,596,019

See accompanying notes to condensed consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	June 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$28,143	$ 51,195
Current Maturities of Long-Term Debt	194	188
Accounts Payable	108,589	113,457
Accrued Salaries and Wages	17,436	19,903
Billings In Excess Of Costs and Estimated Earnings	4,717	13,707
Accrued Taxes	9,652	12,491
Derivative Liabilities	5,513	11,782
Other Accrued Liabilities	8,695	6,532
Liabilities of Discontinued Operations	3,353	3,637
Total Current Liabilities	186,292	232,892
Pensions Benefit Liability	50,516	69,743
Other Postretirement Benefits Liability	45,683	45,221
Other Noncurrent Liabilities	22,248	25,209
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	218,981	195,603
Deferred Tax Credits	27,381	28,288
Regulatory Liabilities	78,695	73,926
Other	754	718
Total Deferred Credits	325,811	298,535
Capitalization		
Long-Term Debt, Net of Current Maturities	498,591	389,589
Cumulative Preferred Shares– Authorized 1,500,000 Shares Without Par Value; Outstanding - None	--	--
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, 2014—36,623,317 Shares; 2013—36,271,696 Shares	183,117	181,358
Premium on Common Shares	263,048	255,759
Retained Earnings	108,834	99,441

Accumulated Other Comprehensive Loss	(1,666)	(1,728)
Total Common Equity	553,333	534,830
Total Capitalization	1,051,924	924,419
Total Liabilities and Equity	$1,682,474	$ 1,596,019

See accompanying notes to condensed 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 June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating Revenues				
Electric	$92,903	$82,838	$211,951	$183,814
Product Sales	101,461	94,557	197,379	185,118
Construction Services	40,247	34,994	65,753	61,411
Total Operating Revenues	234,611	212,389	475,083	430,343
Operating Expenses				
Production Fuel - Electric	12,603	15,603	34,633	33,556
Purchased Power - Electric System Use	16,476	11,245	38,261	27,884
Electric Operation and Maintenance Expenses	39,774	35,805	74,396	68,252
Cost of Products Sold (depreciation included below)	80,178	72,337	154,117	140,124
Cost of Construction Revenues Earned (depreciation included below)	33,881	31,600	56,243	55,875
Other Nonelectric Expenses	15,104	12,176	28,665	25,954
Depreciation and Amortization	14,969	14,835	29,749	29,755
Property Taxes - Electric	3,387	3,009	6,358	5,925
Total Operating Expenses	216,372	196,610	422,422	387,325
Operating Income	18,239	15,779	52,661	43,018
Interest Charges	7,627	6,877	14,222	13,857
Other Income	858	696	2,681	1,557
Income Before Income Taxes—Continuing Operations	11,470	9,598	41,120	30,718
Income Tax Expense—Continuing Operations	1,486	2,094	9,774	7,980
Net Income from Continuing Operations	9,984	7,504	31,346	22,738
Discontinued Operations				
Income - net of Income Tax Expense (Benefit) of $1, $131, $50 and ($74) for the respective periods	9	197	77	116
Gain on Disposition - net of Income Tax Expense of $6 for the six months ended June 30, 2013	--	--	--	210
Net Income from Discontinued Operations	9	197	77	326
Net Income	9,993	7,701	31,423	23,064
Preferred Dividend Requirements and Other Adjustments	--	--	--	513
Earnings Available for Common Shares	$9,993	$7,701	$31,423	$22,551
Average Number of Common Shares Outstanding—Basic	36,409,753	36,170,353	36,325,052	36,122,742
Average Number of Common Shares Outstanding—Diluted	36,652,684	36,373,606	36,568,030	36,325,527
Basic Earnings Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.27	$0.21	$0.87	$0.61
Discontinued Operations	--	--	--	0.01
	$0.27	$0.21	$0.87	$0.62

Diluted Earnings Per Common Share:				
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.27	$0.21	$0.86	$0.61
Discontinued Operations	--	--	--	0.01
	$0.27	$0.21	$0.86	$0.62
Dividends Declared Per Common Share	$0.3025	$0.2975	$0.6050	$0.5950

See accompanying notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Net Income	$9,993	$7,701	$31,423	$23,064
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	--	--	(17)	(25)
Gains (Losses) Arising During Period	36	(80)	19	(85)
Income Tax (Expense) Benefit	(13)	28	(1)	39
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	23	(52)	1	(71)
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 12)	51	146	101	291
Income Tax (Expense)	(20)	(59)	(40)	(117)
Pension and Postretirement Benefit Plans – net-of-tax	31	87	61	174
Total Other Comprehensive Income	54	35	62	103
Total Comprehensive Income	$10,047	$7,736	$31,485	$23,167

See accompanying notes to consolidated financial statements.

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

(in thousands)	Six Months Ended June 30, 2014	2013
Cash Flows from Operating Activities		
Net Income	$31,423	$23,064
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Gain from Sale of Discontinued Operations	--	(210)
Net Income from Discontinued Operations	(77)	(116)
Depreciation and Amortization	29,749	29,755
Deferred Tax Credits	(907)	(955)
Deferred Income Taxes	14,850	9,882
Change in Deferred Debits and Other Assets	129	7,519
Discretionary Contribution to Pension Plan	(20,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	(936)	4,971
Allowance for Equity/Other Funds Used During Construction	(759)	(567)
Change in Derivatives Net of Regulatory Deferral	95	486
Stock Compensation Expense—Equity Awards	736	786
Other—Net	(1,264)	867
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(18,148)	(10,126)
Change in Inventories	(10,057)	(4,075)
Change in Other Current Assets	(2,673)	(783)
Change in Payables and Other Current Liabilities	(20,469)	(1,362)
Change in Interest and Income Taxes Receivable/Payable	2,664	(313)
Net Cash Provided by Continuing Operations	4,356	48,823
Net Cash Used in Discontinued Operations	(185)	(1,971)
Net Cash Provided by Operating Activities	4,171	46,852
Cash Flows from Investing Activities		
Capital Expenditures	(80,749)	(51,153)
Net Proceeds from Disposal of Noncurrent Assets	3,184	1,603
Net Increase in Other Investments	(1,639)	(25)
Net Cash Used in Investing Activities - Continuing Operations	(79,204)	(49,575)
Net Proceeds from Sale of Discontinued Operations	--	12,842
Net Cash Provided by Investing Activities - Discontinued Operations	7	193
Net Cash Used in Investing Activities	(79,197)	(36,540)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	2,785	--
Net Short-Term (Repayments) Borrowings	(23,051)	1,117
Proceeds from Issuance of Common Stock	8,452	1,462
Common Stock Issuance Expenses	(310)	--
Payments for Retirement of Capital Stock	(459)	(15,723)
Proceeds from Issuance of Long-Term Debt	150,000	40,900
Short-Term and Long-Term Debt Issuance Expenses	(516)	(52)

Payments for Retirement of Long-Term Debt	(40,993)	(25,222)
Dividends Paid and Other Distributions	(22,029)	(22,097)
Net Cash Provided by (Used in) Financing Activities - Continuing Operations	73,879	(19,615)
Net Cash Used in Financing Activities - Discontinued Operations	(11)	--
Net Cash Provided by (Used in) Financing Activities	73,868	(19,615)
Net Change in Cash and Cash Equivalents - Discontinued Operations	8	(784)
Net Change in Cash and Cash Equivalents	(1,150)	(10,087)
Cash and Cash Equivalents at Beginning of Period	1,150	52,362
Cash and Cash Equivalents at End of Period	$--	$42,275

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

NOTES TO CONDENSED 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, 2013. Because of seasonal and other factors, the earnings for the three and six month periods ended June 30, 2014 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, 2013.

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. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

The companies in the Construction segment enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs on construction projects. Following are the percentages of the Company's consolidated revenues recorded under the percentage-of-completion method:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Percentage-of-Completion Revenues	14.7%	16.3%	11.9%	14.1%

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

(in thousands)	June 30, 2014	December 31, 2013

Costs Incurred on Uncompleted Contracts	$	389,389	$	361,487
Less Billings to Date		(398,964)		(377,608)
Plus Estimated Earnings Recognized		10,363		6,477
Net Costs in Excess of Billings plus Estimated Earnings on Uncompleted Contracts	$	788	$	(9,644)

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

(in thousands)		June 30, 2014		December 31, 2013
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$	5,505	$	4,063
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts		(4,717)		(13,707)
Net Costs in Excess of Billings plus Estimated Earnings on Uncompleted Contracts	$	788	$	(9,644)

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.

Warranty Reserves

The Company establishes reserves for estimated product warranty costs at the time revenue is recognized based on historical warranty experience and additionally for any known product warranty issues. Certain Company products carry one to fifteen year warranties. Although the Company engages in extensive product quality programs and processes, the Company’s warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures. The warranty reserve balance as of December 31, 2013 and June 30, 2014 relates entirely to products produced by the Company’s former wind tower and waterfront equipment manufacturing companies and is included in liabilities of discontinued operations. See note 17 to condensed consolidated financial statements.

Retainage

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

(in thousands)	June 30, 2014	December 31, 2013
Accounts Receivable Retained by Customers	$7,695	$7,125

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 June 30, 2014 and December 31, 2013:

June 30, 2014 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$2,733
Forward Gasoline Purchase Contracts		83	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	120		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,274	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,264	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	681		
Total Assets	$801	$8,621	$2,733
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$--	$5,513
Total Liabilities	$--	$--	$5,513

December 31, 2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$338
Forward Gasoline Purchase Contracts		62	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,671	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,271	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	866		
Total Assets	$976	$9,004	$338
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$103	$11,679
Total Liabilities	$--	$103	$11,679

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 June 30, 2014 and December 31, 2013, are based on prices indexed to observable prices at an active trading hub. 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 June 30, 2014 Level 3 forward electric basis spreads ranged from $0.00 to $7.28 per megawatt-hour under the active trading hub price. The weighted average price was $40.28 per megawatt-hour.

In the table above, the fair value of the Level 3 forward energy contracts in derivative asset and derivative liability positions as of June 30, 2014 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 and six month periods ended June 30, 2014 and 2013.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the six-month periods ended June 30, 2014 and 2013:

	Six Months Ended June 30,	
(in thousands)	2014	2013
Forward Energy Contracts - Fair Values Beginning of Period	$(11,341)	$(17,782)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	1,161	3,776
Changes in Fair Value of Contracts Entered into in Prior Periods	7,400	1,851
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(2,780)	(12,155)
Net Increase in Value of Open Contracts Entered into in Current Period	--	41
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(2,780)	$(12,114)

Inventories

Inventories consist of the following:

(in thousands)	June 30, 2014	December 31, 2013
Finished Goods	$ 24,732	$ 20,649
Work in Process	11,251	9,942
Raw Material, Fuel and Supplies	46,715	42,090
Total Inventories	$ 82,698	$ 72,681

Goodwill and Other Intangible Assets

In the first quarter of 2014, Aevenia, Inc. (Aevenia) recorded a $289,000 gain on the sale of its data communication installation and services business which, over the years of its existence, did not provide a materially significant impact to Aevenia's operating results. In connection with this sale, Aevenia disposed of $163,000 in goodwill associated with the purchase of this business in May 2004.

The following table summarizes changes to goodwill by business segment during 2014:

(in thousands)	Gross Balance December 31, 2013	Accumulated Impairments	Balance (net of impairments) December 31, 2013	Adjustments to Goodwill in 2014	Balance (net of impairments) June 30, 2014
Manufacturing	$ 12,186	$ --	$ 12,186	$ --	$ 12,186
Plastics	19,302	--	19,302	--	19,302
Construction	7,483	--	7,483	163	7,320
Total	$ 38,971	$ --	$ 38,971	$ 163	$ 38,808

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC 360-10-35, Property, Plant, and Equipment—Overall—Subsequent Measurement. The following table summarizes the components of the Company's intangible assets at June 30, 2014 and December 31, 2013:

June 30, 2014 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 5,359	$ 11,452	66-166 months
Other Intangible Assets	639	352	287	27 months
Total	$ 17,450	$ 5,711	$ 11,739	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	
December 31, 2013 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,935	$ 11,876	72-172 months
Other Intangible Assets Including Contracts	825	473	352	33 months
Total	$ 17,636	$ 5,408	$ 12,228	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	

The amortization expense for these intangible assets was:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Amortization Expense – Intangible Assets	$ 244	$ 244	$ 488	$ 488

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

(in thousands)	2014	2015	2016	2017	2018
Estimated Amortization Expense – Intangible Assets	$977	$977	$945	$849	$849

Supplemental Disclosures of Cash Flow Information

	As of June 30,	
(in thousands)	2014	2013
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions1	$21,992	$14,935
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions2	$4,373	$--

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.

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, has 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 and CCMC is not required to be consolidated in the Company's consolidated financial statements.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the first delivery of coal to Coyote Station, scheduled for May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through June 30, 2014 is $13.0 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 as of June 30, 2014 could be as high as $13.0 million.

Revisions to Presentation

Beginning with the Company's 2013 Annual Report on Form 10-K, the Company is reporting revenues and costs related to the sale of products by its manufacturing and plastic pipe companies separately from the revenues and costs of its construction companies on the face of its consolidated statements of income. Its nonelectric revenues and cost of goods sold for the three and six month periods ended June 30, 2013 have been revised in a similar manner to be consistent with, and comparable to, the presentation of revenues and costs for the three and six month periods ended June 30, 2014. The change in presentation of 2013 nonelectric revenues and cost of goods sold had no effect on the Company's reported consolidated revenues, costs, operating income or net income for the three and six month periods ended June 30, 2013.

New Accounting Standards

Accounting Standards Update (ASU) 2013-11

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) (ASC 740), Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which requires an entity with unrecognized tax benefits to present the unrecognized tax benefits as a reduction to a deferred tax asset related to a net operating loss carryforward, a similar tax loss, or a tax credit carryforward when such net operating loss carryforward, similar tax loss, or tax credit carryforward is available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position. The ASU 2013-11 amendments to ASC 740 are effective for fiscal years beginning after December 15, 2013. The Company adopted the reporting requirements in ASU 2013-11 in the first quarter of 2014 on a prospective basis. The Company's long-term deferred income tax reported on its June 30, 2014 consolidated balance sheet include $4.3 million of unrecognized tax benefits.

ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

ASU 2014-09 amendments to the ASC are effective for fiscal years beginning after December 15, 2016. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. Early application of the ASU amendments is not permitted. The Company is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and evaluating transition options.

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, Plastics and Construction.

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.

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

Construction consists of businesses involved in commercial and industrial electric contracting and construction of fiber optic, electric distribution, water, wastewater and HVAC systems primarily in the central United States.

OTP is a wholly owned subsidiary 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 2013. All of the Company's long-lived assets are within the United States.

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
United States of America	96.1	%	97.6	%	96.8	%	97.7	%
Mexico	2.6	%	1.2	%	2.3	%	1.2	%
Canada	1.1	%	1.1	%	0.8	%	1.0	%
All Other Countries (none greater than 0.06%)	0.2	%	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 six months ended June 30, 2014 and 2013 and total assets by business segment as of June 30, 2014 and December 31, 2013 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Electric	$ 92,911	$ 82,862	$ 211,999	$ 183,872
Manufacturing	53,370	49,793	108,805	102,959
Plastics	48,090	44,761	88,573	82,161
Construction	40,247	34,994	65,753	61,419
Intersegment Eliminations	(7)	(21)	(47)	(68)
Total	$ 234,611	$ 212,389	$ 475,083	$ 430,343

Interest Charges

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Electric	$ 6,059	$ 4,264	$ 11,138	$ 9,072
Manufacturing	813	816	1,621	1,631
Plastics	274	256	521	504
Construction	169	110	269	217
Corporate and Intersegment Eliminations	312	1,431	673	2,433
Total	$ 7,627	$ 6,877	$ 14,222	$ 13,857

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013

Electric	$ (992)	$ (817)	$ 4,758	$ 3,265
Manufacturing	1,336	1,373	3,007	3,591
Plastics	2,114	2,627	4,247	5,230
Construction	1,238	20	829	(703)
Corporate	(2,210)	(1,109)	(3,067)	(3,403)
Total	$ 1,486	$ 2,094	$ 9,774	$ 7,980

Earnings (Loss) Available for Common Shares

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Electric	$ 5,242	$ 3,583	$ 21,895	$ 15,514
Manufacturing	2,300	2,045	5,196	5,363
Plastics	3,433	3,925	6,893	7,812
Construction	1,853	24	1,233	(1,068)
Corporate	(2,844)	(2,073)	(3,871)	(5,396)
Discontinued Operations	9	197	77	326
Total	$ 9,993	$ 7,701	$ 31,423	$ 22,551

Identifiable Assets

(in thousands)	June 30, 2014	December 31, 2013
Electric	$ 1,352,535	$ 1,290,416
Manufacturing	125,870	119,302
Plastics	95,011	76,853
Construction	54,820	49,440
Corporate	54,228	59,970
Discontinued Operations	10	38
Total	$ 1,682,474	$ 1,596,019

3. Rate and Regulatory Matters

Below are descriptions of OTP’s major capital expenditure projects that have had, or will have, a significant impact on OTP’s revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the Federal Energy Regulatory Commission (FERC), impacting OTP’s revenues in 2014 and 2013.

Major Capital Expenditure Projects

Multi-Value Transmission Projects—On December 16, 2010, FERC approved the cost allocation for a new classification of projects in the MISO region 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 areas within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing. On February 24, 2014 the U.S. Supreme Court denied petitions for a writ of certiorari of the United States Court of Appeals, Seventh Circuit decision upholding the FERC’s MVP orders. The petitioners did not seek rehearing. Effective January 1, 2012, the FERC authorized OTP to recover 100% of prudently incurred Construction Work in Progress (CWIP) and Abandoned Plant recovery on two projects approved by MISO as MVPs in MISO’s 2011 Transmission Expansion Plan: the Big Stone South – Brookings MVP and the Big Stone South – Ellendale MVP. Abandoned Plant recovery provides a basis for OTP to request recovery of prudently incurred costs in the event a project is cancelled for reasons beyond OTP’s control. The following projects have been approved by MISO as MVPs under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).

The Big Stone South – Brookings Project—This is a planned 345 kiloVolt (kV) transmission line that will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Xcel Energy jointly developed this project. 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. This line is expected to be in service in 2017. The SDPUC approved the certification for the northern portion of the route on April 9, 2013. The SDPUC granted OTP and Xcel Energy approval of a route permit for the southern portion of the Big Stone South - Brookings line on February 18, 2014. On August 1, 2014 OTP and Xcel Energy entered into agreements to construct the project.

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The Big Stone South – Ellendale Project—This is a proposed 345 kV transmission 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. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. A joint route permit application was filed on August 23, 2013 with the SDPUC. The SDPUC is expected to take formal action on the route permit application in August 2014.

Capacity Expansion 2020 (CapX2020) Transmission Line Projects—CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kV Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji–Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP's CapX2020 transmission investments is through the MISO Tariff (the Brookings Project as an MVP) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (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. The St. Cloud to Alexandria portion of the Fargo Project was placed into service on April 23, 2014. Construction is underway for the remaining portions of the project, which are expected to be in service in 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 also granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The first phase of the 250 mile Brookings Project was energized in March 2014. Additional segments of the line were energized in April 2014. The entire project is expected to be in service in 2015.

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

Big Stone Plant Air Quality Control System (AQCS)—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 the EPA agreed on non-substantive rule revisions, which were adopted by the South Dakota 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 AQCS 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.

OTP is currently in the process of constructing the BART-compliant AQCS at Big Stone Plant for a current projected cost of approximately $384 million (OTP's 53.9% share would be $207 million) with an expected commercial operation date of October 2015. OTP's share of AQCS construction expenditures incurred through June 30, 2014 is $128 million.

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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. OTP requested jurisdictional recovery in Minnesota, North Dakota and South Dakota of amounts it had invested in the Big Stone II Project at the time of its withdrawal, discussed below under the respective jurisdictional sections of this note.

Minnesota

2010 General Rate Case—OTP's most recent general rate increase in Minnesota of approximately $5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 2011. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment.

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 potential options for meeting that standard. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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

The costs for three major wind farms previously approved by the MPUC for recovery through OTP's Minnesota Renewable Resource Adjustment (MNRRA) were 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. The MNRRA rate continued to collect the remaining regulatory asset balance through April 30, 2013, when the balance was estimated to be very near zero. On April 4, 2013 the MPUC authorized that any remaining unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. Effective May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs.

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 transitioned from a conservation spending goal to a conservation energy savings goal in 2010.

The Minnesota Department of Commerce (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

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In December 2012, the MPUC 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. 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 recognized $3.9 million in MNCIP financial incentives in 2013 related to the results of its conservation improvement programs in Minnesota in 2013. On April 1, 2014 OTP submitted its annual 2013 financial incentive filing request for $4.0 million along with a request for an updated surcharge rate. The MNDOC issued comments on July 8, 2014. A decision by the MPUC is expected in the third quarter of 2014.

OTP had a regulatory asset of $7.7 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of June 30, 2014. OTP recognized revenue for Minnesota conservation costs and incentives earned totaling $1.5 million in the three month period ended June 30, 2014, compared with $1.7 million in the three month period ended June 30, 2013, and $3.0 million in the six month period ended June 30, 2014, compared with $3.3 million in the six month period ended June 30, 2013.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. 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. 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.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. On March 26, 2012 the MPUC approved an update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made in transmission facilities that qualify for regional cost allocation under the MISO Tariff, with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but disallowed recovery of capitalized internal costs, costs in excess of CON estimates and a carrying charge in the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of these costs in a future rate case. In response to the MPUC approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. OTP filed its 2014 annual update on May 1, 2014 with a proposed implementation date of July 1, 2014. The MNDOC was granted an extension through August 1, 2014 to issue comments on the 2014 update.

OTP had a regulatory asset of $2.1 million for amounts eligible for recovery through the Minnesota TCR rider that had not been billed to Minnesota customers as of June 30, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota TCR rider of $1.8 million in the three month period ended June 30, 2014, compared with $1.1 million in the three month period ended June 30, 2013, and $4.1 million in the six month period ended June 30, 2014, compared with $2.2 million in the six month period ended June 30, 2013.

Environmental Cost Recovery (ECR) Rider—In a written order issued on January 23, 2012 the MPUC granted OTP's petition for Advance Determination of Prudence (ADP) for costs associated with the design, construction and operation of the BART-compliant AQCS at Big Stone Plant attributable to serving OTP's Minnesota customers. On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file 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 OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements include a current return on the project's CWIP balance at the level approved in OTP's most recent general rate case. The rate charged to customers will be updated in an annual filing with the MPUC until the costs are rolled into base rates at an undetermined future date. OTP filed its 2014 annual update on July 31, 2014 with a proposed implementation date of October 1, 2014.

OTP had a regulatory asset of $0.2 million for amounts eligible for recovery through the Minnesota ECR rider that had not been billed to Minnesota customers as of June 30, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota ECR rider in the three and six month periods ended June 30, 2014 of $1.7 million and $3.5 million, respectively.

Big Stone II Cost Recovery—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 as part of the rates established in that proceeding was $3.2 million. Because OTP will not earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of $3.2 million was discounted to its present value of $2.8 million using OTP's incremental borrowing rate, in accordance with ASC Topic 980, Regulated Operations (ASC 980), accounting requirements. Transmission-related project costs of $3.2 million remained in CWIP as active project costs.

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, along with accumulated Allowance for Funds Used During Construction (AFUDC), were transferred from CWIP to the Big Stone II Unrecovered Project Costs – Minnesota 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 using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of $0.7 million related to the discount in accordance with ASC 980 accounting requirements. In June 2014, OTP recorded an additional discount of $0.3 million to reflect changes in the end date of the anticipated recovery period from September 2020 to December 2022.

North Dakota

General Rates—OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables 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. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered $9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2013. 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 updated rates implemented on April 1, 2013. The NDPSC approved OTP's most recent annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014. The update approved on March 12, 2014 resulted in a 13.5% reduction in the NDRRA rate.

OTP had a net regulatory liability of $1.3 million as of June 30, 2014 for amounts billed to North Dakota customers that were subject to refund through the NDRRA rider. OTP recognized revenue for amounts eligible for recovery through the NDRRA rider of $2.0 million in the three month period ended June 30, 2014, compared with $2.2 million in the three month period ended June 30, 2013, and $3.5 million in the six month period ended June 30, 2014, compared with $4.5 million in the six month period ended June 30, 2013.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014.

OTP had a regulatory asset of $0.4 million for amounts eligible for recovery through the North Dakota TCR rider that had not been billed to North Dakota customers as of June 30, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota TCR rider of $1.7 million in the three month period ended June 30, 2014, compared with $0.9 million in the three month period ended June 30, 2013, and $3.2 million in the six month period ended June 30, 2014, compared with $1.7 million in the six month period ended June 30, 2013.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP's application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. On December 18, 2013 the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. On March 31, 2014 OTP filed its annual update to its North Dakota ECR rider rate with a proposed implementation date of July 1, 2014. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. On July 10, 2014 the NDPSC approved OTP's 2014 ECR rider annual update request with an August 1, 2014 implementation date.

OTP had a regulatory asset of $2.2 million as of June 30, 2014 for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of June 30, 2014. OTP recognized revenue for amounts eligible for recovery through the North Dakota ECR rider of $1.5 million in the three month period ended June 30, 2014, compared with ($0.3) million in the three month period ended June 30, 2013, and $3.0 million in the six month period ended June 30, 2014, compared with $0.4 million in the six month period ended June 30, 2013.

Big Stone II Cost Recovery—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 total amount of Big Stone II generation costs incurred by OTP (which excluded $2.6 million of project transmission-related costs) was determined to be $10.1 million, of which $4.1 million represents North Dakota's jurisdictional share.

OTP included in its total recovery amount a carrying charge of approximately $0.3 million on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs begins based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP will not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of $4.3 million was discounted to its then present value of $3.9 million using OTP's incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs was 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. 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. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling $1.0 million. As of April 1, 2014 North Dakota customer's bills no longer include a charge for North Dakota share of Big Stone II costs. OTP had a regulatory liability of $0.1 million as of June 30, 2014 for amounts billed to North Dakota customers that will be subject to refund through the North Dakota TCR rider's annual update. The North Dakota TCR rider annual update request is expected to be filed by September 1, 2014.

South Dakota

2010 General Rate Case—On April 21, 2011 the SDPUC issued a written order approving an overall final revenue increase of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50% for the interim rates and final rates for OTP in South Dakota. Final rates were effective with bills rendered on and after June 1, 2011.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. The SDPUC approved an annual update to OTP's South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP's most recent annual update to its South Dakota TCR on February 18, 2014 with an effective date of March 1, 2014.

OTP had a regulatory asset of $0.1 million for amounts eligible for recovery through the South Dakota TCR rider that had not been billed to South Dakota customers as of June 30, 2014. OTP recognized revenue for amounts eligible for recovery through the South Dakota TCR rider of $0.4 million in the three month period ended June 30, 2014, compared with $0.3 million in the three month period ended June 30, 2013, and $0.7 million in the six month period ended June 30, 2014, compared with $0.3 million in the six month period ended June 30, 2013.

Environmental Cost Recovery Rider—On March 30, 2012 OTP requested approval from the SDPUC for an ECR rider to recover costs associated with the Big Stone Plant AQCS. 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 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 Cost Recovery—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 is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. 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. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

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 regulatory asset accounts, which had a combined balance of $0.9 million on June 30, 2014.

Federal

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

Effective January 1, 2010 the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate: (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is invested.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint at the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO's transmission rates to a proposed 9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. The complaint is pending at the FERC.

United States Environmental Protection Agency (EPA) Cross-State Air Pollution Rule (CSAPR)
On April 29, 2014 the U.S. Supreme Court issued its opinion in litigation concerning EPA's CSAPR, reversing the August 21, 2012 decision of the U.S. Court of Appeals for the D.C. Circuit that had vacated CSAPR. The Supreme Court's opinion does not remove or otherwise address the D.C. Circuit's December 30, 2011 order staying CSAPR. CSAPR was remanded to the D.C. Circuit for further proceedings, where the United States has moved the court lift the previously–entered stay. Oppositions to the motion to lift the stay were due July 31, 2014. A ruling on the motion is expected in August 2014. Therefore, at this time, implementation and compliance dates for the rule are unknown.

The CSAPR rule that was vacated in 2012 would have applied to OTP's Solway gas peaking plant and the Hoot Lake coal-fired plant in Minnesota. The primary impact of the rule would have been for Hoot Lake Plant to acquire sulfur dioxide (SO_2) allowances to continue operating at historical levels. Based on Hoot Lake's historical generation and EPA's predicted allowance costs at the time of the 2012 rule, CSAPR would have resulted in annual SO_2 allowance purchase costs of approximately $1.0 million. At this time, the future impact of CSAPR is unknown.

EPA Proposed Carbon Dioxide (CO_2) Emissions Standards and Guidelines
On January 8, 2014, the EPA published proposed standards of performance for CO_2 emissions from new fossil fuel-fired power plants, based on implementation of partial carbon capture and storage for coal-fired units and natural gas combined cycle technology for gas-fired units. On June 18, 2014 the EPA published proposed CO_2 emission guidelines for existing fossil fuel-fired power plants, based on a combination of heat-rate improvements, re-dispatch of electricity to lower-emitting natural gas units or non-emitting renewable energy and nuclear units, and demand-side energy efficiency measures. At the same time, the EPA published separate CO_2 emission standards for reconstructed and modified fossil fuel-fired power plants essentially requiring that such plants install modern technology, when modifying or reconstructing, to reduce their emissions. The EPA plans to issue final rules for each of these proposals by July 2015. For existing sources, states would then be required to develop and submit plans, either individually or with other states, spelling out how they will achieve the individualized, reduced CO_2 emission rates that the EPA has identified. Those state plans are due by July 2016. The EPA is proposing to allow, upon reasonable request, one-year extensions for states proposing individual plans and two-year extensions for states proposing to submit multi-state plans.

OTP is participating with other stakeholders in efforts to shape the final performance standards for new, modified and reconstructed, and existing power plants both at the federal level and, where applicable, at the state level. It is not possible to determine, at this time, the potential impact to OTP of these future regulations on new, modified or reconstructed, or existing sources.

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:

		June 30, 2014		Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits1	$3,992	$53,063	$57,055	see note
Conservation Improvement Program Costs and Incentives2	2,668	5,134	7,802	24 months
Deferred Marked-to-Market Losses1	2,615	2,898	5,513	54 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,915	4,915	asset lives
Big Stone II Unrecovered Project Costs – Minnesota1	575	3,443	4,018	102 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	1,986	1,555	3,541	24 months
Debt Reacquisition Premiums1	358	2,066	2,424	219 months
Deferred Income Taxes1	--	2,221	2,221	asset lives
North Dakota Environmental Cost Recovery Rider Accrued Revenues2	2,173	--	2,173	12 months
Minnesota Transmission Rider Accrued Revenues2	1,076	1,012	2,088	24 months
Recoverable Fuel and Purchased Power Costs1	1,849	--	1,849	12 months
Big Stone II Unrecovered Project Costs – South Dakota2	100	793	893	107 months
North Dakota Renewable Resource Rider Accrued Revenues2	392	--	392	12 months
North Dakota Transmission Rider Accrued Revenues2	368	--	368	12 months
Minnesota Environmental Cost Recovery Rider Accrued Revenues2	178	--	178	12 months
South Dakota Transmission Rider Accrued Revenues2	93	--	93	12 months
Minnesota Renewable Resource Rider Accrued Revenues2	--	68	68	see note
Total Regulatory Assets	$18,423	$77,168	$95,591	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$72,497	$72,497	asset lives
Deferred Marked-to-Market Gains	614	2,119	2,733	50 months
Deferred Income Taxes	--	1,778	1,778	asset lives
	--	1,662	1,662	21 months

North Dakota Renewable Resource Rider Accrued Refund				
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	536	536	see note
Big Stone II Over Recovered Project Costs – North Dakota	144	--	144	2 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	103	109	234 months
South Dakota – Nonasset-Based Margin Sharing Excess	26	--	26	12 months
Total Regulatory Liabilities	$790	$78,695	$79,485	
Net Regulatory Asset (Liability) Position	$17,633	$(1,527)	$16,106	

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, 2013 Current	Long-Term	Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits1	$4,095	$55,012	$59,107	see note
Deferred Marked-to-Market Losses1	3,008	8,674	11,682	60 months
Conservation Improvement Program Costs and Incentives2	4,945	3,959	8,904	18 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,646	4,646	asset lives
Big Stone II Unrecovered Project Costs – Minnesota1	558	3,967	4,525	81 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	1,351	1,753	3,104	24 months
Debt Reacquisition Premiums1	351	2,241	2,592	225 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues2	2,331	--	2,331	12 months
Deferred Income Taxes1	--	1,805	1,805	asset lives
Big Stone II Unrecovered Project Costs – South Dakota2	101	843	944	113 months
North Dakota Renewable Resource Rider Accrued Revenues2	--	762	762	15 months
Recoverable Fuel and Purchased Power Costs1	760	--	760	12 months
Big Stone II Unrecovered Project Costs – North Dakota1	375	--	375	3 months
Minnesota Renewable Resource Rider Accrued Revenues2	--	68	68	see note
South Dakota Transmission Rider Accrued Revenues2	32	--	32	12 months
Deferred Holding Company Formation Costs1	27	--	27	6 months
General Rate Case Recoverable Expenses – South Dakota1	6	--	6	1 month
Total Regulatory Assets	$17,940	$83,730	$101,670	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$71,454	$71,454	asset lives
Deferred Income Taxes	--	1,960	1,960	asset lives
Minnesota Transmission Rider Accrued Refund	670	--	670	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	289	289	see note
North Dakota Renewable Resource Rider Accrued Refund	261	--	261	12 months
North Dakota Transmission Rider Accrued Refund	215	--	215	12 months
Deferred Marked-to-Market Gains	6	117	123	56 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	5	106	111	240 months
South Dakota – Nonasset-Based Margin Sharing Excess	38	--	38	12 months

Total Regulatory Liabilities	$1,195	$73,926	$75,121
Net Regulatory Asset Position	$16,745	$9,804	$26,549

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.

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

All Deferred Marked-to-Market Gains and Losses recorded as of June 30, 2014 are related to forward purchases of energy scheduled for delivery through December 2018.

The Accumulated ARO Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

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

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 June 30, 2014 balance is being amortized on a straight-line basis over two consecutive 12-month periods that began in January 2014.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 219 months.

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

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the North Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

Minnesota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to Minnesota customers as of June 30, 2014.

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

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of June 30, 2014.

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to North Dakota customers as of June 30, 2014.

Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the Minnesota share of amounts invested in the construction of the Big Stone Plant AQCS project, net of amounts billed under the rider.

South Dakota Transmission Rider Accrued Revenues relate to revenues earned 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 June 30, 2014.

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. On April 4, 2013 the MPUC approved OTP's request to set the MNRRA rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case.

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

The North Dakota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of June 30, 2014.

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.

Big Stone II Over Recovered Project Costs – North Dakota represent amounts collected from North Dakota customers in excess of 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. The June 30, 2014 liability will be refunded to North Dakota customers through an adjustment to revenue requirements under the North Dakota TCR rider.

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 June 30, 2014 OTP had no net unrealized gains on open forward contracts for the purchase or 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 June 30, 2014 and December 31, 2013, and the change in the Company’s consolidated balance sheet position from December 31, 2013 to June 30, 2014 and December 31, 2012 to June 30, 2013:

(in thousands)	June 30, 2014	December 31, 2013
Current Asset – Marked-to-Market Gain	$ 2,733	$ 338
Regulatory Asset – Current Deferred Marked-to-Market Loss	2,615	3,008
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	2,898	8,674
Total Assets	8,246	12,020
Current Liability – Marked-to-Market Loss	(5,513)	(11,782)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(614)	(6)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(2,119)	(117)
Total Liabilities	(8,246)	(11,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ --	$ 115

(in thousands)	Year-to-Date June 30, 2014	Year-to-Date June 30, 2013
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$ 115	$ 49
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(72)	(49)
Changes in Fair Value of Contracts Entered into in Prior Periods	(43)	--
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	--	40

Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ --	$ 40

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Net (Losses) Gains on Forward Electric Energy Contracts	$ (9)	$ 28	$ (13)	$ 254

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

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of June 30, 2014 and December 31, 2013:

	June 30, 2014		December 31, 2013	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$503	2	$856	3
Net Credit Risk to Single Largest Counterparty	$395		$530	

OTP had a net credit risk exposure to two counterparties with investment grade credit ratings. OTP had no exposure at June 30, 2014 or December 31, 2013 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The 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 June 30, 2014. 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 amounts of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of June 30, 2014 and December 31, 2013 are indicated in the following table:

(in thousands)	June 30, 2014	December 31, 2013
Derivative assets subject to legally enforceable netting arrangements	$ 2,816	$ 400
Derivative liabilities subject to legally enforceable netting arrangements	(5,513)	(11,782)
Net balance subject to legally enforceable netting arrangements	$ (2,697)	$ (11,382)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of June 30, 2014 and December 31, 2013:

Current Liability – Marked-to-Market Loss (in thousands)	June 30, 2014	December 31, 2013
Loss Contracts Covered by Deposited Funds or Letters of Credit	$--	$ --
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	5,513	11,679
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	103
Total Current Liability – Marked-to-Market Loss	$5,513	$ 11,782
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	$5,513	$ 11,679
Offsetting Gains with Counterparties under Master Netting Agreements	(2,733)	(117)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$2,780	$ 11,562

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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, 2013	$181,358	$255,759	$99,441	$ (1,728)	$534,830
Common Stock Issuances, Net of Expenses	1,861	6,878			8,739
Common Stock Retirements	(102)	(357)			(459)
Net Income			31,423		31,423
Other Comprehensive Income				62	62
Tax Benefit – Stock Compensation		32			32
Employee Stock Incentive Plans Expense		736			736
Common Dividends ($0.605 per share)			(22,030)		(22,030)
Balance, June 30, 2014	$183,117	$263,048	$108,834	$ (1,666)	$553,333

Common Shares

In 2014, the Company began issuing shares to meet the requirements of its Automatic Dividend Reinvestment and Share Purchase Plan, Employee Stock Purchase Plan and Employee Stock Ownership Plan, rather than purchasing shares in the open market. Following is a reconciliation of the Company's common shares outstanding from December 31, 2013 through June 30, 2014:

Common Shares Outstanding, December 31, 2013	36,271,696
Issuances:	
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	88,237
Cash Invested	42,071
At-the-Market Offering	86,909
Employee Stock Purchase Plan:	
Cash Invested	19,661
Dividends Reinvested	12,512
Restricted Stock Issued to Employees	26,700
Employee Stock Ownership Plan	22,650
Executive Stock Performance Awards (2011-2013 shares earned)	22,630
Stock Options Exercised	19,150
Restricted Stock Issued to Directors	16,800
Vesting of Restricted Stock Units	14,305
Directors Deferred Compensation	498
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(16,127)
Forfeiture of Unvested Restricted Stock	(4,375)
Common Shares Outstanding, June 30, 2014	36,623,317

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is earnings available for common shares with no adjustments for the three and six month periods ended June 30, 2014 and 2013. 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. Adjustments to the denominator used to calculate diluted earnings per share of 242,931 shares and 203,253 shares for the three month periods ended June 30, 2014 and 2013, respectively, and 242,978 shares and 202,785 shares for the six month periods ended June 30, 2014 and 2013, respectively, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in any of the periods.

7. Share-Based Payments

The Company has five share-based payment programs.

2014 Stock Incentive Plan
On April 14, 2014 the Company's shareholders approved the Company's 2014 Stock Incentive Plan. The 2014 Stock Incentive Plan allows the Company to provide compensation through various stock-based arrangements.

Stock Incentive Awards
On April 14, 2014 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 2014 Stock Incentive Plan:

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Granted to Nonemployee Directors	16,800	$ 29.41	25% per year through April 8, 2018
Restricted Stock Granted to Executive Officers	26,700	$ 29.41	25% per year through April 8, 2018
Stock Performance Awards Granted to Executive Officers	115,200	$ 22.94	December 31, 2016
Restricted Stock Units Granted to Employees	11,800	$ 24.95	100% on April 8, 2018

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 150,400 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, 2014 through December 31, 2016. The aggregate target share award is 115,200 shares. Actual payment may range from zero to 150% 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 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, Stock Compensation (ASC 718), and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

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

Under the terms of the award agreements, all outstanding (unvested) shares or units held by a retiring grantee vest immediately on normal retirement. When the Company is made aware of a retirement or pending retirement, the Company accelerates recognition of compensation expense related to the unvested awards to correspond with the remaining service period of the grantee in accordance with the requirements of ASC 718.

In connection with the resignation of an executive officer in May 2014, the following awards were forfeited: unvested shares of restricted stock: 1,000 granted in 2012, 1,275 granted in 2013 and 2,100 granted in 2014; unvested stock performance awards: 6,600 granted in 2012, 4,900 granted in 2013 and 8,900 granted in 2014; and 5,500 unvested restricted stock units granted in 2011.

As of June 30, 2014 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 2.4 years.

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

(in thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Employee Stock Purchase Plan (15% discount)	$ 45	$ 42	$ 87	$ 59
Restricted Stock Granted to Directors	98	162	221	369
Restricted Stock Granted to Employees	207	112	342	204
Restricted Stock Units Granted to Employees	28	79	86	154
Stock Performance Awards Granted to Executive Officers	518	703	1,044	1,801
Totals	$ 896	$ 1,098	$ 1,780	$ 2,587

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 or OTP, respectively, did not meet certain financial covenants. As of June 30, 2014 the Company and OTP were 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, 2013 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 45.0% and 55.0%. OTP's equity to total capitalization ratio including short-term debt was 47.4% as of June 30, 2014. Total capitalization for OTP cannot currently exceed $987 million.

9. Commitments and Contingencies

Construction and Other Purchase Commitments
At December 31, 2013 OTP had commitments under contracts in connection with construction programs aggregating approximately $108.2 million. At June 30, 2014 OTP had commitments under contracts in connection with construction programs aggregating approximately $79.0 million. The decrease in construction commitments from December 31, 2013 to June 30, 2014 is mainly for OTP's share of commitments related to the construction of the Big Stone Plant AQCS pertaining to materials and services ordered or under contract as of December 31, 2013 that were received in the first six months of 2014.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending through 2038. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2014, 2015, 2016 and 2040. In the first six months of 2014, OTP entered into no additional agreements for the purchase of coal to meet its future coal requirements or for the purchase of capacity or energy to meet its future energy requirements.

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 June 30, 2014 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of June 30, 2014 and December 31, 2013:

(in thousands)	Line Limit	In Use on June 30, 2014	Restricted due to Outstanding Letters of Credit	Available on June 30, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$150,000	$ 25,273	$ 309	$ 124,418	$ 149,341
OTP Credit Agreement	170,000	2,870	2,330	164,800	116,975
Total	$320,000	$ 28,143	$ 2,639	$ 289,218	$ 266,316

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 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 Series A Notes) and $90 million aggregate principal amount of OTP’s 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). On February 27, 2014 OTP issued all $150 million aggregate principal amount of the Notes.

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 Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B 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 OTP 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 became effective upon 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.

On February 27, 2014 OTP used a portion of the proceeds of the Notes to retire OTP's $40.9 million unsecured term loan under a Credit Agreement with JPMorgan Chase Bank, N.A., and to repay $82.5 million of short-term debt then outstanding under OTP's Second Amended and Restated Credit Agreement (the OTP Credit Agreement). Remaining proceeds of the Notes have been used to fund OTP 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 June 30, 2014 and December 31, 2013:

June 30, 2014 (in thousands)	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$2,870	$ 25,273	$ 28,143
Long-Term Debt:			
9.000% Notes, due December 15, 2016		$ 52,330	52,330
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 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018	--	291	291
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	--	1,165	1,165
Total	$445,000	$ 53,786	$ 498,786
Less: Current Maturities	--	194	194
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$445,000	$ 53,591	$ 498,591
Total Short-Term and Long-Term Debt (with current maturities)	$447,870	$ 79,058	$ 526,928

December 31, 2013 (in thousands)	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$51,195	$ --	$ 51,195
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		$ 52,330	52,330
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
North Dakota Development Note, 3.95%, due April 1, 2018	--	325	325
PACE Note, 2.54%, due March 18, 2021	--	1,223	1,223
Total	$335,900	$ 53,878	$ 389,778
Less: Current Maturities	--	188	188
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$335,900	$ 53,689	$ 389,589
Total Short-Term and Long-Term Debt (with current maturities)	$387,095	$ 53,877	$ 440,972

12. Pension Plan and Other Postretirement Benefits

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

(in thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Service Cost—Benefit Earned During the Period	$ 1,174	$ 1,418	$ 2,349	$ 2,836
Interest Cost on Projected Benefit Obligation	3,285	3,036	6,570	6,072
Expected Return on Assets	(4,186)	(3,632)	(8,373)	(7,264)
Amortization of Prior-Service Cost:				
From Regulatory Asset	65	83	129	166
From Other Comprehensive Income1	1	2	3	4
Amortization of Net Actuarial Loss:				
From Regulatory Asset	868	1,663	1,736	3,326
From Other Comprehensive Income1	23	45	46	90
Net Periodic Pension Cost	$ 1,230	$ 2,615	$ 2,460	$ 5,230

1Corporate cost included in Other Nonelectric Expenses.

Cash flows—The Company made discretionary plan contributions totaling $20,000,000 in January 2014. The Company currently is not required and does not expect to make an additional contribution to the plan in 2014. The Company also made a discretionary plan contribution of $10,000,000 in January 2013.

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

(in thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Service Cost—Benefit Earned During the Period	$ 12	$ 13	$ 25	$ 26
Interest Cost on Projected Benefit Obligation	380	352	760	704
Amortization of Prior-Service Cost:				
From Regulatory Asset	6	5	11	10
From Other Comprehensive Income1	13	13	26	26
Amortization of Net Actuarial Loss:				
From Regulatory Asset	36	52	71	104
From Other Comprehensive Income2	11	78	23	156
Net Periodic Pension Cost	$ 458	$ 513	$ 916	