Otter Tail Corp
Form 10-Q
May 12, 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	March 31, 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:

April 30, 2014 – 36,471,911 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	March 31, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and Cash Equivalents	$6,613	$1,150
Accounts Receivable:		
Trade—Net	99,892	83,572
Other	11,523	9,790
Inventories	81,875	72,681
Deferred Income Taxes	39,352	35,452
Unbilled Revenues	16,902	18,157
Costs and Estimated Earnings in Excess of Billings	3,719	4,063
Regulatory Assets	20,199	17,940
Other	11,336	7,747
Assets of Discontinued Operations	38	38
Total Current Assets	291,449	250,590
Investments	8,753	9,362
Other Assets	29,605	28,834
Goodwill	38,808	38,971
Other Intangibles—Net	13,084	13,328
Deferred Debits		
Unamortized Debt Expense	4,498	4,188
Regulatory Assets	78,839	83,730
Total Deferred Debits	83,337	87,918
Plant		
Electric Plant in Service	1,473,685	1,460,884
Nonelectric Operations	196,500	194,872
Construction Work in Progress	207,442	187,461
Total Gross Plant	1,877,627	1,843,217
Less Accumulated Depreciation and Amortization	686,460	676,201
Net Plant	1,191,167	1,167,016
Total Assets	$1,656,203	$1,596,019

See accompanying notes to condensed consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	March 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$11,899	$51,195
Current Maturities of Long-Term Debt	191	188
Accounts Payable	104,486	113,457
Accrued Salaries and Wages	13,556	19,903
Billings In Excess Of Costs and Estimated Earnings	10,077	13,707
Accrued Taxes	14,057	12,491
Derivative Liabilities	8,252	11,782
Other Accrued Liabilities	8,272	6,532
Liabilities of Discontinued Operations	3,442	3,637
Total Current Liabilities	174,232	232,892
Pensions Benefit Liability	50,129	69,743
Other Postretirement Benefits Liability	45,547	45,221
Other Noncurrent Liabilities	21,367	25,209
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	212,682	195,603
Deferred Tax Credits	27,834	28,288
Regulatory Liabilities	75,365	73,926
Other	733	718
Total Deferred Credits	316,614	298,535
Capitalization		
Long-Term Debt, Net of Current Maturities	498,640	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—36,412,491 Shares; 2013—36,271,696 Shares	182,062	181,358
Premium on Common Shares	259,454	255,759

Retained Earnings	109,878	99,441
Accumulated Other Comprehensive Loss	(1,720)	(1,728)
Total Common Equity	549,674	534,830
Total Capitalization	1,048,314	924,419
Total Liabilities and Equity	$1,656,203	$1,596,019

See accompanying notes to condensed consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended March 31, 2014	2013
Operating Revenues		
Electric	$119,048	$100,976
Product Sales	95,918	90,561
Construction Services	25,506	26,417
Total Operating Revenues	240,472	217,954
Operating Expenses		
Production Fuel - Electric	22,030	17,953
Purchased Power - Electric System Use	21,785	16,639
Electric Operation and Maintenance Expenses	34,622	32,447
Cost of Products Sold (depreciation included below)	73,939	67,787
Cost of Construction Revenues Earned (depreciation included below)	22,362	24,275
Other Nonelectric Expenses	13,561	13,778
Depreciation and Amortization	14,780	14,920
Property Taxes - Electric	2,971	2,916
Total Operating Expenses	206,050	190,715
Operating Income	34,422	27,239
Interest Charges	6,595	6,980
Other Income	1,823	861
Income Before Income Taxes from Continuing Operations	29,650	21,120
Income Tax Expense – Continuing Operations	8,288	5,886
Net Income from Continuing Operations	21,362	15,234
Discontinued Operations		
Income (Loss) - net of Income Tax Expense (Benefit) of $49 and ($205) for the respective periods	68	(81)
Gain on Disposition - net of Income Tax Expense of $6 for the three months ended March 31, 2013	--	210
Net Income from Discontinued Operations	68	129
Net Income	21,430	15,363
Preferred Dividend Requirements and Other Adjustments	--	513
Earnings Available for Common Shares	$21,430	$14,850
Average Number of Common Shares Outstanding—Basic	36,240,350	36,075,131
Average Number of Common Shares Outstanding—Diluted	36,431,915	36,259,115
Basic Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.59	$0.41
Discontinued Operations	--	--
	$0.59	$0.41
Diluted Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement and other adjustments)	$0.59	$0.41

Discontinued Operations	--	--
	$0.59	$0.41
Dividends Declared Per Common Share	$0.3025	$0.2975

See accompanying notes to condensed consolidated financial statements.

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

(in thousands)	Three Months Ended March 31, 2014	2013
Net Income	$21,430	$15,363
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)
(Losses) Arising During Period	(17)	(5)
Income Tax Benefit	12	11
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(22)	(19)
Pension and Postretirement Benefit Plans:		
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 12)	50	145
Income Tax (Expense)	(20)	(58)
Pension and Postretirement Benefit Plans – net-of-tax	30	87
Total Other Comprehensive Income	8	68
Total Comprehensive Income	$21,438	$15,431

See accompanying notes to condensed consolidated financial statements.

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

(in thousands)	Three Months Ended March 31, 2014	2013
Cash Flows from Operating Activities		
Net Income	$21,430	$15,363
Adjustments to Reconcile Net Income to Net Cash (Used in) Provided by Operating Activities:		
Net Gain from Sale of Discontinued Operations	--	(210)
Net (Income) Loss from Discontinued Operations	(68)	81
Depreciation and Amortization	14,780	14,920
Deferred Tax Credits	(454)	(483)
Deferred Income Taxes	12,872	6,139
Change in Deferred Debits and Other Assets	(888)	4,800
Discretionary Contribution to Pension Plan	(20,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	(2,408)	1,975
Allowance for Equity/Other Funds Used During Construction	(340)	(293)
Change in Derivatives Net of Regulatory Deferral	118	378
Stock Compensation Expense—Equity Awards	358	392
Other—Net	(255)	25
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(17,884)	(13,423)
Change in Inventories	(9,234)	(4,062)
Change in Other Current Assets	(1,599)	(3,025)
Change in Payables and Other Current Liabilities	(16,363)	(3,440)
Change in Interest and Income Taxes Receivable/Payable	1,013	1,076
Net Cash (Used in) Provided by Continuing Operations	(18,922)	10,213
Net Cash Used in Discontinued Operations	(135)	(2,400)
Net Cash (Used in) Provided by Operating Activities	(19,057)	7,813
Cash Flows from Investing Activities		
Capital Expenditures	(37,690)	(23,327)
Net Proceeds from Disposal of Noncurrent Assets	1,505	729
Net Increase in Other Investments	(989)	(923)
Net Cash Used in Investing Activities - Continuing Operations	(37,174)	(23,521)
Net Proceeds from Sale of Discontinued Operations	--	10,465
Net Cash Provided by (Used in) Investing Activities - Discontinued Operations	7	(208)
Net Cash Used in Investing Activities	(37,167)	(13,264)
Cash Flows from Financing Activities		
Net Short-Term (Repayments) Borrowings	(39,296)	1,335
Proceeds from Issuance of Common Stock	3,666	1,156
Payments for Retirement of Capital Stock	(242)	(15,500)
Proceeds from Issuance of Long-Term Debt	150,000	40,900
Short-Term and Long-Term Debt Issuance Expenses	(502)	(7)
Payments for Retirement of Long-Term Debt	(40,946)	(25,178)

Dividends Paid and Other Distributions	(10,993)	(11,307)
Net Cash Provided by (Used in) Financing Activities	61,687	(8,601)
Net Change in Cash and Cash Equivalents - Discontinued Operations	--	(778)
Net Change in Cash and Cash Equivalents	5,463	(14,830)
Cash and Cash Equivalents at Beginning of Period	1,150	52,362
Cash and Cash Equivalents at End of Period	$6,613	$37,532

See accompanying notes to condensed consolidated financial statements.

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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 months ended March 31, 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) 815, Derivatives and Hedging. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

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

	Three Months Ended March 31,	
	2014	2013
Percentage-of-Completion Revenues	9.1 %	12.1 %

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

	March 31,	December 31,

(in thousands)	2014	2013
Costs Incurred on Uncompleted Contracts	$364,005	$361,487
Less Billings to Date	(377,991)	(377,608)
Plus Estimated Earnings Recognized	7,628	6,477
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$(6,358)	$(9,644)

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

(in thousands)	March 31, 2014	December 31, 2013
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$3,719	$4,063
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(10,077)	(13,707)
Net Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	$(6,358)	$(9,644)

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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 March 31, 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)	March 31, 2014	December 31, 2013	
Accounts Receivable Retained by Customers	$6,352	$7,125	1

1 Includes $89,000 related to one project with an expected completion date beyond December 31, 2014.

Fair Value Measurements

The Company follows Accounting Standards Codification (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 March 31, 2014 and December 31, 2013:

March 31, 2014 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$1,609
Forward Gasoline Purchase Contracts		20	
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	120		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,438	
U.S. Government Debt Securities – Held by Captive Insurance Company		964	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	745		
Total Assets	$865	$8,422	$1,609
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$--	$8,252
Total Liabilities	$--	$--	$8,252

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 March 31, 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 March 31, 2014 Level 3 forward electric price inputs ranged from $1.52 to $7.00 per megawatt-hour under the active trading hub price. The weighted average price was $36.77 per megawatt-hour.

In the table above, $1,569,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and $8,252,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of March 31, 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 month periods ended March 31, 2014 or 2013.

The remaining $40,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position as of March 31, 2014 are related to financial contracts that will not be settled by physical delivery of electricity but will be settled financially by the counterparty to the contract paying or receiving the difference between the contract price and the market price at the hour of scheduled delivery. The related forward energy sales contracts are not offset by forward energy purchase contracts. Therefore, the $40,000 in derivative gains related to these contracts as of March 31, 2014 are subject to change in subsequent reporting periods or on settlement. These contracts are scheduled for settlement in April and May of 2014. Any fluctuation in the factors used in the fair valuation of these contracts would not result in a significant change to the fair value of the contracts.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the three month periods ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
(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	1,160	2,195
Changes in Fair Value of Contracts Entered into in Prior Periods	3,498	3,320
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(6,683)	(12,267)
Net Gain Recognized as Regulatory Assets on contract entered into in Period	40	32
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(6,643)	$(12,235)

Inventories

Inventories consist of the following:

(in thousands)	March 31, 2014	December 31, 2013
Finished Goods	$ 25,611	$ 20,649
Work in Process	9,654	9,942
Raw Material, Fuel and Supplies	46,610	42,090

Total Inventories	$	81,875	$	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) March 31, 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 March 31, 2014 and December 31, 2013:

March 31, 2014 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 5,147	$11,664	15 – 25 years
Other Intangible Assets Including Contracts	825	505	320	5 – 30 years
Total	$ 17,636	$ 5,652	$11,984	
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	15 – 25 years
Other Intangible Assets Including Contracts	825	473	352	5 – 30 years
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:

(in thousands)	Three Months Ended March 31, 2014	2013

Amortization Expense – Intangible Assets	$ 244	$ 244

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

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Supplemental Disclosures of Cash Flow Information

(in thousands)	As of March 31, 2014	2013
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions1	$22,244	$8,901
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions2	$3,434	$--

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 March 31, 2014 is $10.9 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 March 31, 2014 could be as high as $10.9 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 months ended March 31, 2013 have been revised in a similar manner to be consistent with, and comparable to, the presentation of revenues and costs for the three months ended March 31, 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 month period ended March 31, 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 March 31, 2014 consolidated balance sheet include $4.3 million of unrecognized tax benefits.

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 and horticultural containers. 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 March 31,			
	2014		2013	
United States of America	97.5	%	97.9	%
Mexico	1.9	%	1.2	%
Canada	0.5	%	0.9	%
All Other Countries (none individually greater than 0.05%)	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 months ended March 31, 2014 and 2013 and total assets by business segment as of March 31, 2014 and December 31, 2013 are presented in the following tables:

Operating Revenue

	Three Months Ended March 31,	
(in thousands)	2014	2013
Electric	$ 119,088	$ 101,010
Manufacturing	55,435	53,166
Plastics	40,483	37,400
Construction	25,506	26,425
Intersegment Eliminations	(40)	(47)
Total	$ 240,472	$ 217,954

Interest Charges

	Three Months Ended March 31,	
(in thousands)	2014	2013
Electric	$ 5,079	$ 4,808
Manufacturing	808	815
Plastics	247	248
Construction	100	107
Corporate and Intersegment Eliminations	361	1,002
Total	$ 6,595	$ 6,980

Income Taxes

	Three Months Ended March 31,	
(in thousands)	2014	2013
Electric	$ 5,750	$ 4,082
Manufacturing	1,671	2,218
Plastics	2,133	2,603
Construction	(409)	(723)
Corporate	(857)	(2,294)
Total	$ 8,288	$ 5,886

Earnings Available for Common Shares

	Three Months Ended March 31,	
(in thousands)	2014	2013
Electric	$ 16,653	$ 11,931

Manufacturing	2,896	3,318
Plastics	3,460	3,887
Construction	(620)	(1,092)
Corporate	(1,027)	(3,323)
Discontinued Operations	68	129
Total	$ 21,430	$ 14,850

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Identifiable Assets

(in thousands)	March 31, 2014	December 31, 2013
Electric	$ 1,334,155	$ 1,290,416
Manufacturing	125,800	119,302
Plastics	95,779	76,853
Construction	46,800	49,440
Corporate	53,631	59,970
Discontinued Operations	38	38
Total	$ 1,656,203	$ 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. 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. 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. 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 is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. 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.

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. A joint route permit application was filed on August 23, 2013 with the SDPUC. OTP and MDU jointly filed an Application for a Certificate of Corridor Compatibility along with an application for a route permit with the NDPSC on October 18, 2013.

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 April 23, 2014. Construction is underway for the remaining portions of the project.

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 on April 29, 2014.

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 March 31, 2014 is $113 million.

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, which are discussed below.

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. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. Because the request to extend the period of the new rate for 18 months was still under review, a supplemental filing was submitted on February 15, 2013, requesting that the current rate be retained until a majority of the remaining costs were recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the February 15, 2013 request on April 4, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. 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, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

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

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 with a proposed implementation date of July 1, 2014.

OTP had a regulatory asset of $8.1 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of March 31, 2014. OTP recognized revenue for Minnesota conservation costs and incentives earned totaling $1.5 million in the three month period ended March 31, 2014, compared with $1.6 million in the three month period ended March 31, 2013.

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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 compliance filings in April 2014 seeking no rate change. OTP filed its 2014 annual update on May 1, 2014 with a proposed implementation date of July 1, 2014.

OTP had a regulatory asset of $1.2 million as of March 31, 2014 for amounts eligible for recovery through the Minnesota TCR rider that had not been billed to Minnesota customers as of March 31, 2014. OTP recognized revenue for amounts eligible for recovery through the Minnesota TCR rider of $2.3 million in the three month period ended March 31, 2014, compared with $1.0 million in the three month period ended March 31, 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 will be updated in an annual filing with the MPUC until the costs are rolled into base rates at an undetermined future date.

OTP had a regulatory liability of $0.1 million as of March 31, 2014 for amounts billed to Minnesota customers that were subject to refund through the Minnesota ECR rider. OTP recognized revenue for amounts eligible for recovery through the Minnesota ECR rider of $1.8 million in the three month period ended March 31, 2014.

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 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 of $2.8 million using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of $0.7 million related to the discount in accordance with ASC 980 accounting requirements. The amount of the discount is expected to be recovered, along with the remaining balance of the Big Stone II Unrecovered Project Costs – Minnesota regulatory asset, over an anticipated 89-month recovery period which began in May 2013.

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 March 31, 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 $1.4 million in the three month period ended March 31, 2014, compared with $2.3 million in the three month period ended March 31, 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 liability of less than $0.1 million as of March 31, 2014 for amounts billed to North Dakota customers that were subject to refund through the North Dakota TCR rider. OTP recognized revenue for amounts eligible for recovery through the North Dakota TCR rider of $1.5 million in the three month period ended March 31, 2014, compared with $0.8 million in the three month period ended March 31, 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. The ECR rider rate will continue to be updated at least annually in a filing with the NDPSC until the project costs are rolled into base rates at an undetermined future date.

OTP had a regulatory asset of $2.1 million as of March 31, 2014 for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of March 31, 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 March 31, 2014, compared with $0.7 million in the three month period ended March 31, 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 is including 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 March 31, 2014 for amounts billed to North Dakota customers that will be subject to refund through the North Dakota TCR rider.

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 as of March 31, 2014 for amounts eligible for recovery through the South Dakota TCR rider that had not been billed to South Dakota customers as of March 31, 2014. OTP recognized revenue for amounts eligible for recovery through the South Dakota TCR rider of $0.3 million in the three month period ended March 31, 2014, compared with $0.1 million in the three month period ended March 31, 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 an Allowance for Funds Used During Construction (AFUDC) on these costs and request recovery of, and a return on, the accumulated costs, including AFUDC, in a future rate filing in South Dakota.

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Big Stone 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 long-term regulatory asset account.

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.

Environmental Protection Agency (EPA) Cross-State Air Pollution Rule (CSPAR)
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 will now be remanded to the D.C. Circuit for further proceedings; however, CSAPR will continue to be stayed until the D.C. Circuit in the future lifts or modifies the stay. 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 (SO2) 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 SO2 allowance purchase costs of approximately $1.0 million.

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:

	March 31, 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	$4,043	$54,038	$58,081	see note
Deferred Marked-to-Market Losses1	3,258	4,994	8,252	57 months
Conservation Improvement Program Costs and Incentives2	3,533	4,580	8,113	15 months
Accumulated ARO Accretion/Depreciation Adjustment1	--	4,779	4,779	asset lives
Big Stone II Unrecovered Project Costs – Minnesota1	566	3,857	4,423	78 months
Recoverable Fuel and Purchased Power Costs1	3,540	--	3,540	12 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up1	1,452	1,419	2,871	21 months
Debt Reacquisition Premiums1	361	2,154	2,515	222 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues2	2,071	--	2,071	15 months
Deferred Income Taxes1	--	2,013	2,013	asset lives
Minnesota Transmission Rider Accrued Revenues2	1,153	--	1,153	12 months
Big Stone II Unrecovered Project Costs – South Dakota2	101	818	919	110 months
North Dakota Renewable Resource Rider Accrued Revenues2	--	119	119	24 months
South Dakota Transmission Rider Accrued Revenues2	107	--	107	12 months
Minnesota Renewable Resource Rider Accrued Revenues2	--	68	68	see note
Deferred Holding Company Formation Costs1	14	--	14	3 months
Total Regulatory Assets	$20,199	$78,839	$99,038	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$71,943	$71,943	asset lives
Deferred Income Taxes	--	1,869	1,869	asset lives
Deferred Marked-to-Market Gains	533	1,037	1,570	53 months
North Dakota Renewable Resource Rider Accrued Refund	1,436	--	1,436	12 months
	--	412	412	see note

Revenue for Rate Case Expenses Subject to Refund – Minnesota				
Big Stone II Over Recovered Project Costs – North Dakota	144	--	144	6 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	104	110	237 months
Minnesota Environmental Cost Recovery Rider Accrued Refund	56	--	56	12 months
North Dakota Transmission Rider Accrued Refund	32	--	32	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	21	--	21	12 months
Total Regulatory Liabilities	$2,228	$75,365	$77,593	
Net Regulatory Asset Position	$17,971	$3,474	$21,445	

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.

All Deferred Marked-to-Market Gains and Losses recorded as of March 31, 2014 are related to forward purchases of energy scheduled for delivery through December 2018.

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

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

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 March 31, 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 222 months.

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.

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

Minnesota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that have not been billed to Minnesota customers as of March 31, 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 March 31, 2014 and that are not scheduled to be recovered prior to March 31, 2015.

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 March 31, 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 March 31, 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 March 31, 2014 liability will be refunded to North Dakota customers through an adjustment to revenue requirements under the North Dakota TCR rider.

The Minnesota Environmental Cost Recovery Rider Accrued refund relates to amounts billed under the Minnesota ECR rider in excess of an allowed return granted on the Minnesota share of amounts invested in the construction of the Big Stone Plant AQCS project.

The North Dakota Transmission Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers net of transmission revenues that are refundable to North Dakota customers as of March 31, 2014.

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 March 31, 2014 OTP had recognized, on a pretax basis, $39,000 in net unrealized gains on open forward contracts for the 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 March 31, 2014 and December 31, 2013, and the change in the Company's consolidated balance sheet position from December 31, 2013 to March 31, 2014 and December 31, 2012 to March 31, 2013:

(in thousands)	March 31, 2014	December 31, 2013
Current Asset – Marked-to-Market Gain	$ 1,609	$ 338
Regulatory Asset – Current Deferred Marked-to-Market Loss	3,258	3,008
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	4,994	8,674
Total Assets	9,861	12,020
Current Liability – Marked-to-Market Loss	(8,252)	(11,782)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(533)	(6)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(1,037)	(117)
Total Liabilities	(9,822)	(11,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 39	$ 115

(in thousands)	Year-to-Date March 31, 2014	Year-to-Date March 31, 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	39	81
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 39	$ 81

The $39,000 in recognized but unrealized gains on the forward energy sales contracts marked to market on March 31, 2014 are expected to be realized on settlement as scheduled in April and May of 2014.

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

	Three Months Ended March 31,	
(in thousands)	2014	2013
Net (Loss) Gain on Forward Electric Energy Contracts	$ (4)	$ 226

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

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

	March 31, 2014		December 31, 2013	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$128	3	$856	3
Net Credit Risk to Single Largest Counterparty	$83		$530	

OTP had a net credit risk exposure to three counterparties with investment grade credit ratings. OTP had no exposure at March 31, 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 March 31, 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 March 31, 2014 and December 31, 2013 are indicated in the following table:

(in thousands)	March 31, 2014	December 31, 2013
Derivative assets subject to legally enforceable netting arrangements	$ 1,629	$ 400
Derivative liabilities subject to legally enforceable netting arrangements	(8,252)	(11,782)
Net balance subject to legally enforceable netting arrangements	$ (6,623)	$ (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 March 31, 2014 and December 31, 2013:

Current Liability – Marked-to-Market Loss (in thousands)	March 31, 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	8,252	11,679
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	103
Total Current Liability – Marked-to-Market Loss	$8,252	$ 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	$8,252	$ 11,679
Offsetting Gains with Counterparties under Master Netting Agreements	(1,569)	(117)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$6,683	$ 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	748	3,504			4,252
Common Stock Retirements	(44)	(198)			(242)
Net Income			21,430		21,430
Other Comprehensive Income				8	8
Tax Benefit – Stock Compensation		31			31
Employee Stock Incentive Plans Expense		358			358
Common Dividends			(10,993)		(10,993)
Balance, March 31, 2014	$182,062	$259,454	$109,878	$ (1,720)	$549,674

Common Shares

In 2014, the Company began issuing shares to meet the requirements of its dividend reinvestment, employee stock ownership, and employee stock purchase plans and shareholder stock purchase program, rather than purchasing shares in the open market. Following is a reconciliation of the Company’s common shares outstanding from December 31, 2013 through March 31, 2014:

Common Shares Outstanding, December 31, 2013	36,271,696
Issuances:	
Dividend Reinvestments	49,402
Employee Stock Ownership Plan	22,650
Executive Stock Performance Awards (2011-2013 shares earned)	22,630
Employee Stock Purchase Plan	19,661
Shareholder Stock Purchase Program	18,681
Stock Options Exercised	16,650
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(8,879)
Common Shares Outstanding, March 31, 2014	36,412,491

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 month periods ended March 31, 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 191,565 shares and 183,984 shares for the three month periods ended March 31, 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 either quarter.

7. Share-Based Payments

The Company has five share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2014. As of March 31, 2014 the remaining unrecognized compensation expense related to stock-based compensation was approximately $3.6 million (before income taxes) which will be amortized over a weighted-average period of 1.8 years.

Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three month periods ended March 31, 2014 and 2013 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2014	2013
Employee Stock Purchase Plan (15% discount)	$ 42	$ 17
Restricted Stock Granted to Directors	123	207
Restricted Stock Granted to Employees	135	92
Restricted Stock Units Granted to Employees	58	75
Stock Performance Awards Granted to Executive Officers	526	1,098
Totals	$ 884	$ 1,489

8. Retained Earnings Restriction

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

Both the Company and OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of March 31, 2014 the Company was in compliance with the debt covenants. See note 10 to the Company's financial statements on Form 10-K for the year ended December 31, 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 44.8% and 54.8%. OTP's equity to total capitalization ratio including short-term debt was 47.2% as of March 31, 2014. Total capitalization for OTP cannot currently exceed $874 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 March 31, 2014 OTP had commitments under contracts in connection with construction programs aggregating approximately $103.2 million. The decrease in construction commitments from December 31, 2013 to March 31, 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 quarter 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. OTP entered into no additional agreements for the purchase of capacity or to meet energy requirements or for the purchase of coal to meet its remaining coal requirements in the first quarter of 2014.

Contingencies

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to, environmental remediation, litigation matters and the resolution of matters related to open tax years. Should all of these known items result in liabilities being incurred, the loss could be as high as $2.0 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 March 31, 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 March 31, 2014 and December 31, 2013:

(in thousands)	Line Limit	In Use on March 31, 2014	Restricted due to Outstanding Letters of Credit	Available on March 31, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$150,000	$11,899	$ 659	$137,442	$149,341
OTP Credit Agreement	170,000	--	3,830	166,170	116,975
Total	$320,000	$11,899	$ 4,489	$303,612	$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 will be 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 March 31, 2014 and December 31, 2013:

March 31, 2014 (in thousands)	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$ 11,899	$ 11,899
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
Other Obligations - Various up to 3.95% at March 31, 2014	--	1,502	1,502
Total	$445,000	$ 53,832	$ 498,832
Less: Current Maturities	--	191	191
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$445,000	$ 53,640	$ 498,640
Total Short-Term and Long-Term Debt (with current maturities)	$445,000	$ 65,730	$ 510,730

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
Other Obligations - Various up to 3.95% at December 31, 2013	--	1,548	1,548
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

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12. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended March 31,	
(in thousands)	2014	2013
Service Cost—Benefit Earned During the Period	$1,175	$1,418
Interest Cost on Projected Benefit Obligation	3,285	3,036
Expected Return on Assets	(4,187)	(3,632)
Amortization of Prior-Service Cost:		
From Regulatory Asset	64	83
From Other Comprehensive Income1	2	2
Amortization of Net Actuarial Loss:		
From Regulatory Asset	868	1,663
From Other Comprehensive Income1	23	45
Net Periodic Pension Cost	$1,230	$2,615

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:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Service Cost—Benefit Earned During the Period	$13	$13
Interest Cost on Projected Benefit Obligation	380	352
Amortization of Prior-Service Cost:		
From Regulatory Asset	5	5
From Other Comprehensive Income1	13	13
Amortization of Net Actuarial Loss:		
From Regulatory Asset	35	52
From Other Comprehensive Income2	12	78
Net Periodic Pension Cost	$458	$513
1Amortization of Prior Service Costs from Other Comprehensive Income Charged to:		
Electric Operation and Maintenance Expenses	$5	$5
Other Nonelectric Expenses	8	8
2Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:		
Electric Operation and Maintenance Expenses	$33	$48
Other Nonelectric Expenses	(21)	30

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

	Three Months Ended March 31,	
(in thousands)	2014	2013
Service Cost—Benefit Earned During the Period	$315	$441
Interest Cost on Projected Benefit Obligation	558	610
Amortization of Prior-Service Cost:		
From Regulatory Asset	51	51
From Other Comprehensive Income1	1	1
Amortization of Net Actuarial Loss:		
From Regulatory Asset	--	248
From Other Comprehensive Income1	--	6
Net Periodic Postretirement Benefit Cost	$925	$1,357
Effect of Medicare Part D Subsidy	$(308)	$(564)

1 Corporate cost included in other nonelectric expenses.

13. Fair Value of Financial Instruments

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

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

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of March 31, 2014 related to the Otter Tail Corporation Credit Agreement and December 31, 2013 related to the OTP Credit Agreement were subject to a variable interest rates of LIBOR plus 1.75% and LIBOR plus 1.25%, respectively, which approximate market rates.

Long-Term Debt including Current Maturities—The fair value of the Company's and OTP's long-term debt is estimated based on the current market indications of rates available to the Company for the issuance of debt. The Company's long-term debt subject to variable interest rates approximates fair value. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820, Fair Value Measurement.

	March 31, 2014		December 31, 2013	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 6,613	$ 6,613	$ 1,150	$ 1,150
Short-Term Debt	$ (11,899)	$ (11,899)	(51,195)	(51,195)
Long-Term Debt including Current Maturities	$ (498,831)	$ (546,269)	(389,777)	(427,796)

15. Income Tax Expense – Continuing Operations

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the three month periods ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Income Before Income Taxes – Continuing Operations	$29,650	$21,120
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	11,563	8,237
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(2,252)	(1,589)
Section 199 Domestic Production Activities Deduction	(358)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212)	(223)
Employee Stock Ownership Plan Dividend Deduction	(189)	(190)
AFUDC Equity	(133)	(115)
Corporate Owned Life Insurance	(112)	(302)
Other Items – Net	(19)	68

Income Tax Expense – Continuing Operations	$8,288		$5,886	
Effective Income Tax Rate – Continuing Operations	28.0	%	27.9	%

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

(in thousands)		2014		2013
Balance on January 1	$	4,239	$	4,436
Increases Related to Tax Positions for Prior Years		137		--
Uncertain Positions Adjusted During Year		--		--
Balance on March 31	$	4,376	$	4,436

The balance of unrecognized tax benefits as of March 31, 2014 would not reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of March 31, 2014 is not expected to change significantly within the next twelve months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. No interest is accrued on tax uncertainties as of March 31, 2014.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of March 31, 2014, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2010. On September 13, 2013 the IRS and U.S. Treasury issued final regulations on the deductibility and capitalization of expenditures related to tangible property, generally effective for tax years beginning on or after January 1, 2014. Taxpayers were allowed to elect early adoption of the regulations for the 2012 or 2013 tax year. Deferred tax liabilities at March 31, 2014 are not materially affected by the regulations. The final regulations do not impact the effect of Revenue Procedure 2013-24 issued on April 30, 2013, which provided guidance for repairs related to generation property. Among other things, the Revenue Procedure listed units of property and material components of units of property for purposes of analyzing repair versus capitalization issues. The Company will adopt Revenue Procedure 2013-24 and the final tangible property regulations for income tax filings for tax year 2014.

17. Discontinued Operations

On February 8, 2013 the Company completed the sale of substantially all the assets of its waterfront equipment manufacturing company formerly included in the Company's Manufacturing segment, for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013. On November 30, 2012 the Company completed the sale of the assets of its former wind tower manufacturing company and on February 29, 2012 the Company completed the sale of DMS Health Technologies, Inc. (DMS) and recorded an additional $0.2 million gain on the sale in the first quarter of 2013 related to a working capital true up. Following are summary presentations of the results of discontinued operations for the three-month periods ended March 31, 2014 and 2013, which mainly includes residual revenues and expenses from the Company's former wind tower and waterfront equipment manufacturers and the additional $0.2 million gain on the sale of DMS in the first quarter of 2013:

	For the Three Months Ended March 31,	
(in thousands)	2014	2013
Operating Revenues	$ --	$ 2,009
Operating Expenses	(117)	2,707
Operating Income (Loss)	117	(698)
Other Income	--	412
Income Tax Benefit	(49)	(205)
Net Income (Loss) from Operations	68	(81)
Gain on Disposition Before Taxes	--	216
Income Tax Expense on Disposition	--	6
Net Gain on Disposition	--	210
Net Income	$ 68	$ 129

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of March 31, 2014 and December 31, 2013:

(in thousands)	March 31, 2014	December 31, 2013
Current Assets	$ 38	$ 38
Assets of Discontinued Operations	$ 38	$ 38
Current Liabilities	$ 3,442	$ 3,637
Liabilities of Discontinued Operations	$ 3,442	$ 3,637

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

(in thousands)	2014	2013
Warranty Reserve Balance, January 1	$ 3,087	$ 5,027
Provision for Warranties Used During the Year	--	120
Less Settlements Made During the Year	--	(583)
Decrease in Warranty Estimates for Prior Years	(100)	(63)
Warranty Reserve Balance, March 31	$ 2,987	$ 4,501

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The warranty reserve balances as of March 31, 2014 and December 31, 2013 relate entirely to products produced by the Company’s former wind tower and waterfront equipment manufacturing companies. Expenses associated with remediation activities of these companies could be substantial. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company’s consolidated statements of income, the Company retains responsibility for warranty claims related to the products they produced prior to the sales of these companies. For wind towers, the potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. For example, if the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company’s consolidated results of operations and financial condition.

18. Subsequent Events

2014 Stock Incentive Plan
On April 14, 2014 the Company’s shareholders approved the Company’s 2014 Stock Incentive Plan. The Company’s 2014 Stock Incentive Plan allows the Company to provide compensation through various stock-based arrangements. The material terms of the 2014 Stock Incentive Plan are disclosed in the Company’s Proxy Statement for its 2014 Annual Meeting of Shareholders filed with the Securities and Exchange Commission (SEC) on March 3, 2014. The 2014 Stock Incentive Plan was filed as Exhibit 4.1 to the Company’s Registration Statement on Form S-8 filed with the SEC on April 17, 2014.

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.

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

RESULTS OF OPERATIONS

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three months ended March 31, 2014 and 2013, followed by a discussion of changes in our consolidated financial position during the three months ended March 31, 2014 and our business outlook for the remainder of 2014.

Comparison of the Three Months Ended March 31, 2014 and 2013

Consolidated operating revenues were $240.5 million for the three months ended March 31, 2014 compared with $218.0 million for the three months ended March 31, 2013. Operating income was $34.4 million for the three months ended March 31, 2014 compared with $27.2 million for the three months ended March 31, 2013. The Company recorded diluted earnings per share from continuing operations and total diluted earnings per share of $0.59 for the three months ended March 31, 2014 compared to $0.41 for the three months ended March 31, 2013.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and construction revenues earned and other nonelectric operating expenses for the three month periods ended March 31, 2014 and 2013 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations (in thousands)	March 31, 2014	March 31, 2013
Operating Revenues:		
Electric	$ 40	$ 34
Nonelectric	--	13
Cost of Products Sold	2	12
Cost of Construction Revenues Earned	--	1
Other Nonelectric Expenses	38	34

Electric

(in thousands)	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013	Change	% Change
Retail Sales Revenues	$ 105,504	$ 92,323	$ 13,181	14.3
Wholesale Revenues – Company Generation	4,900	1,633	3,267	200.1
Net Revenue – Energy Trading Activity	(269)	345	(614)	(178.0)
Other Revenues	8,953	6,709	2,244	33.4
Total Operating Revenues	$ 119,088	$ 101,010	$ 18,078	17.9
Production Fuel	22,030	17,953	4,077	22.7
Purchased Power – System Use	21,785	16,639	5,146	30.9
Other Operation and Maintenance Expenses	34,622	32,447	2,175	6.7

Depreciation and Amortization	10,763	10,631	132	1.2
Property Taxes	2,971	2,916	55	1.9
Operating Income	$ 26,917	$ 20,424	$ 6,493	31.8
Electric kilowatt-hour (kwh) Sales (in thousands)				
Retail kwh Sales	1,397,891	1,310,312	87,579	6.7
Wholesale kwh Sales – Company Generation	73,305	64,345	8,960	13.9
Wholesale kwh Sales – Purchased Power Resold	1,611	13,789	(12,178)	(88.3)
Heating Degree Days	4,089	3,671	418	11.4

Retail sales revenue increased $13.2 million as a result of:

a $5.7 million increases in fuel clause adjustment revenues and fuel and purchased power costs recovered in base rates, driven by an 8.2% increase in fuel costs per kwh generated at Otter Tail Power Company's (OTP) fuel fired generating units and a 43.2% increase in prices for power purchased to serve retail customers as a result of higher demand due to colder weather in the first quarter of 2014 compared to the first quarter of 2013,

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a $3.4 million increase in revenues related to the 6.7% increase in retail kwh sales, of which: $1.8 million is attributed to colder weather in 2014, $0.8 million is related to increased sales to a pipeline customer and approximately $0.8 million is from increased sales to residential and commercial customers due, in part, to improved economic conditions and customer growth in OTP's service territory,

a $2.6 million increase in Environmental Cost Recovery rider revenues related to earning a return in Minnesota and North Dakota on increasing amounts invested in the Air Quality Control System (AQCS) under construction at Big Stone Plant, and

a $2.3 million increase in Transmission Cost Recovery rider revenues resulting from increased investment in transmission lines,

offset by:

a $0.9 million decrease in Renewable Resource Adjustment (RRA) rider revenues in North Dakota as a result of: (1) declining book values of renewable assets due to depreciation and (2) reduced RRA revenue requirements related to earning more federal Production Tax Credits (PTCs) as a result of a 33.0% increase in kwhs generated by OTP's wind turbines eligible for PTCs.

Net revenue from energy trading activities, including net mark-to-market gains and losses on forward energy contracts, decreased $0.6 million mainly as a result of decreased trading activity and the incurrence of losses on contracts entered into and settled in the first quarter of 2014.

Wholesale electric revenues from company-owned generation increased $3.3 million as a result of a 163% increase in revenue per wholesale kwh sold and a 13.9% increase in wholesale kwhs sold. The increase in wholesale kwh sales and prices was driven by increased wholesale market demand resulting from colder weather in the first quarter of 2014. OTP was able to serve the higher demand of both wholesale and retail customers as a result of improved availability of Coyote Station, which was shut down for generator repairs during the first seven weeks of 2013, and as a result of the 30.9% increase in kwhs generated from OTP's wind turbines.

Other electric operating revenues increased $2.2 million, reflecting:

a $1.4 million increase in Midcontinent Independent System Operator, Inc. (MISO) tariff revenues resulting from increased investment in regional transmission lines and returns on and recovery of CapX2020 and MISO-designated Multi-Value Project (MVP) investment costs and operating expenses, and

a $0.8 million increase in revenue from various other sources including a $0.3 million increase in transmission related revenue under an integrated transmission agreement and a $0.2 million increase in revenue from steam sales at Big Stone Plant.

Production fuel costs increased $4.1 million as a result of a 13.4% increase in kwhs generated from OTP's steam-powered and combustion turbine generators in combination with an 8.2% increase in the cost of fuel per kwh generated. The increase in kwh generation was facilitated by the improved availability of Coyote Station.

The cost of purchased power to serve retail customers increased $5.1 million due to a 43.2% increase in costs per kwh purchased, partially offset by an 8.5% decrease in kwhs purchased. The increase in costs per kwh purchased was driven by increased wholesale market demand resulting from colder weather.

Electric operating and maintenance expenses increased $2.2 million as a result of:

a $1.2 million increase in MISO transmission tariff charges related to increasing investments in regional CapX2020 projects and MISO-designated MVPs,

a $1.2 million increase in labor costs due to increased wages and hours worked and accrued incentives related to OTP's improved performance quarter over quarter, and

increases of $0.1 million to $0.2 million in each of the following categories of expense: generating plant material and supplies, electric grid software maintenance, travel expenses, regulatory assessment charges and insurance premiums,

offset by:

a $1.3 million decrease in labor loading charges as a result of a reduction in pension and postretirement benefit costs related to an increase in discount rates and pension fund contributions.

Manufacturing

(in thousands)	Three Months Ended March 31, 2014	2013	Change	% Change
Operating Revenues	$ 55,435	$ 53,166	$ 2,269	4.3
Cost of Products Sold	42,199	39,326	2,873	7.3
Operating Expenses	5,225	4,498	727	16.2
Depreciation and Amortization	2,620	2,993	(373)	(12.5)
Operating Income	$ 5,391	$ 6,349	$ (958)	(15.1)

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

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, increased $4.9 million mainly as a result of increased sales to manufacturers of recreational equipment.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased $2.6 million, mainly due to a significant reduction in sales of a high volume product that a customer began producing on its own in 2014.

The increase in cost of products sold in our Manufacturing segment relates to the following:

Cost of products sold at BTD increased $4.9 million as a result of increased material costs related to an increase in sales volume and increases in support salaries, wages and product handling costs to support anticipated sales growth in 2014.

Cost of products sold at T.O. Plastics decreased $2.0 million as a result of decreased material costs related to T.O. Plastics lower sales volume.

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

Operating expenses at BTD increased $0.7 million due to increases in administrative and general expenses related to increased labor and benefit costs.

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

Depreciation expense decreased $0.3 million at BTD as a result of certain assets reaching the end of their depreciable lives.

Plastics

(in thousands)	Three Months Ended March 31, 2014	2013	Change	% Change
Operating Revenues	$ 40,483	$ 37,400	$ 3,083	8.2
Cost of Products Sold	31,742	28,473	3,269	11.5
Operating Expenses	2,117	1,436	681	47.4

Depreciation and Amortization	853	774	79	10.2
Operating Income	$ 5,771	$ 6,717	$ (946)	(14.1)

The increase in Plastics segment revenue is the result of a 10.3% increase in pounds of polyvinyl chloride (PVC) pipe sold, partially offset by a 1.8% decrease in the price per pound of pipe sold. States with significant increases in sales were Colorado, California, Arizona, Nevada, Texas and Minnesota. Cost of products sold increased by $3.3 million, mostly due to the increase in sales volume, but also due to a 1.1% increase in the cost per pound of pipe sold related to higher PVC resin costs. A $0.7 million increase in operating expenses, mainly related to increased wage and benefit costs, in combination with the $0.2 million reduction in gross margins resulted in the $0.9 million decline in Plastics segment operating income between the quarters.

Construction

(in thousands)	Three Months Ended March 31, 2014	2013	Change	% Change
Operating Revenues	$ 25,506	$ 26,425	$ (919)	(3.5)
Cost of Construction Revenues Earned	22,362	24,276	(1,914)	(7.9)
Operating Expenses	3,850	3,386	464	13.7
Depreciation and Amortization	512	462	50	10.8
Operating Loss	$ (1,218)	$ (1,699)	$ 481	28.3

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

Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, decreased $1.8 million mainly as a result of a reduction in work volume between the quarters, but Foley's profitability and performance improved on jobs in progress in the first quarter of 2014.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $0.9 million between the quarters as a result of a higher volume of electrical transmission, distribution, substation and underground work in 2014, despite challenging weather conditions.

The decrease in cost of construction revenues earned in our Construction segment relates to the following:

Cost of construction revenues earned at Foley decreased $2.8 million mainly as a result of the reduction in material costs and lower work volume.

Cost of construction revenues earned at Aevenia increased $0.8 million between the quarters as a result of increased material and labor costs related to an increase in construction activity at Aevenia.

Foley's operating expenses for wages and benefits increased $0.5 million between the quarters, due in part to bonuses and in part to severance payments related to workforce reductions.

Corporate

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

(in thousands)	Three Months Ended March 31, 2014	2013	Change	% Change
Operating Expenses	$ 2,407	$ 4,492	$ (2,085)	(46.4)
Depreciation and Amortization	32	60	(28)	(46.7)

Corporate operating expenses decreased $2.1 million reflecting:

a $1.0 million reduction in benefit costs, mainly related to stock-based compensation costs which were higher in the first quarter of 2013 as a result of a 24% increase in the market value of the Company’s common stock in that quarter,

a $0.9 million increase in corporate operating expenses allocated or directly charged to the corporation’s operating segments, and

a $0.2 million decrease in general insurance and contracted services fees.

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Interest Charges

The $385,000 decrease in interest charges in the first three months of 2014 compared with the first three months of 2013, reflects:

a $1,073,000 reduction in interest expense related to the early retirement of $47.7 million of our 9.0% unsecured notes due December 15, 2016, in November 2013,

offset by:

a $644,000 increase in interest expense related to the February 27, 2014 issuance of $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044.

Other Income

The $1.0 million increase in other income in the three months ended March 31, 2014 compared with the three months ended March 31, 2013 includes a $0.8 million gain on the sale of an investment in tax-credit-qualified low income housing rental property, and a $0.3 million gain on the sale of Aevenia's data communication installation and services business, both sold in the first quarter of 2014.

Income Taxes – Continuing Operations

Income taxes - continuing operations increased $2.4 million in the first quarter of 2014 compared with the first quarter of 2013.

The following table provides a reconciliation of income tax expense calculated at the Company's net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the three month periods ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Income Before Income Taxes – Continuing Operations	$29,650	$21,120
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	11,563	8,237
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(2,252)	(1,589)
Section 199 Domestic Production Activities Deduction	(358)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212)	(223)
Employee Stock Ownership Plan Dividend Deduction	(189)	(190)
AFUDC Equity	(133)	(115)
Corporate Owned Life Insurance	(112)	(302)
Other Items – Net	(19)	68
Income Tax Expense – Continuing Operations	$8,288	$5,886
Effective Income Tax Rate – Continuing Operations	28.0%	27.9%

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP’s kwh generation from its wind turbines eligible for PTCs increased 33.0% in the three months ended March 31, 2014 compared with the three months ended March 31, 2013. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Discontinued Operations

On February 8, 2013 we completed the sale of substantially all the assets of our former waterfront equipment manufacturing company, formerly included in our Manufacturing segment, for approximately $13.0 million in cash and received a working capital true up of approximately $2.4 million in June 2013. On November 30, 2012 we completed the sale of the assets of our former wind tower manufacturing company and on February 29, 2012 we completed the sale of DMS Health Technologies, Inc. (DMS) and recorded an additional $0.2 million gain on the sale in the first quarter of 2013 related to a working capital true up. Following are summary presentations of the results of discontinued operations for the three-month periods ended March 31, 2014 and 2013, which mainly includes residual revenues and expenses from our former wind tower and waterfront equipment manufacturers and the additional $0.2 million gain on the sale of DMS in the first quarter of 2013:

	For the Three Months Ended March 31,	
(in thousands)	2014	2013
Operating Revenues	$ --	$ 2,009
Operating Expenses	(117)	2,707
Operating Income (Loss)	117	(698)
Other Income	--	412
Income Tax Benefit	(49)	(205)
Net Income (Loss) from Operations	68	(81)
Gain on Disposition Before Taxes	--	216
Income Tax Expense on Disposition	--	6
Net Gain on Disposition	--	210
Net Income	$ 68	$ 129

FINANCIAL POSITION

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

(in thousands)	Line Limit	In Use on March 31, 2014	Restricted due to Outstanding Letters of Credit	Available on March 31, 2014	Available on December 31, 2013
Otter Tail Corporation Credit Agreement	$ 150,000	$ 11,899	$ 659	$ 137,442	$ 149,341
OTP Credit Agreement	170,000	--	3,830	166,170	116,975
Total	$ 320,000	$ 11,899	$ 4,489	$ 303,612	$ 266,316

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2012 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 10, 2015. On May 14, 2012, we entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million.

Equity or debt financing will be required in the period 2014 through 2018 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our common stock dividend payments have exceeded our net income (losses) in four of the last five years. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions that are allowed to be made by our subsidiaries. See note 8 to condensed consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the Board of Directors. On February 3, 2014 our Board of Directors increased the quarterly dividend from $0.2975 to $0.3025 per common share.

Cash used in operating activities of continuing operations was $18.9 million for the three months ended March 31, 2014 compared with cash provided by operating activities of continuing operations of $10.2 million for the three months ended March 31, 2013. Contributing to the $29.1 million shift in cash provided by operating activities in the first quarter of 2013 to cash used in operating activities in the first quarter of 2014 was a $21.2 million increase in cash used for working capital items from $22.9 million in the first quarter of 2013 to $44.1 million in the first quarter of 2014, and a $10.0 million increase in discretionary contributions to our pension plan between the quarters. Accounts receivable and inventories in the Plastics segment increased $19.3 million in the first quarter of 2014 compared with an increase of $9.2 million in the first quarter of 2013. The greater increase in receivables and inventories in the Plastic segment in 2014 corresponds with a 10.3% increase in sales volume, 8.2% increase in revenues and higher material and labor costs between the quarters. Foley’s accounts payable and billings in excess of costs decreased $9.2 million in the first quarter of 2014 compared with a $1.3 million increase in accounts payable and billings in excess of costs in the first quarter of 2013.

Net cash used in investing activities of continuing operations was $37.2 million for the three months ended March 31, 2014 compared to $23.5 million for the three months ended March 31, 2013 due to a $14.4 million increase in cash used for capital expenditures in the Electric segment between the quarters, as construction of the Big Stone Plant AQCS remains on pace and OTP continues to invest in major transmission grid upgrades and improvements. Net proceeds from the sale of discontinued operations of $10.5 million in the first quarter of 2013 reflect $12.2 million in net proceeds from the sale of the assets of our former waterfront equipment manufacturer net of a $1.7 million working capital settlement paid to the buyer of DMS, which we sold in the first quarter of 2012.

Net cash provided by financing activities in the three months ended March 31, 2014 of $61.7 million compares with net cash used in investing activities in the three months ended March 31, 2014 of $8.6 million. Net cash provided by financing activities in the first quarter of 2014 mainly reflects the issuance by OTP of $150 million in privately placed unsecured notes in two series on February 27, 2014, and the use of a portion of the proceeds of the notes to retire OTP’s $40.9 million unsecured term loan and to repay short-term debt outstanding under the OTP Credit Agreement which was being used to finance OTP’s construction activities. First quarter 2014 financing activities also reflect the payment of $11.0 million in common stock dividends, OTP’s repayment of $51.2 million in short-term debt outstanding under the OTP Credit Agreement on December 31, 2013 and the borrowing of $11.9 million under the Otter Tail Corporation Credit Agreement to fund the working capital needs of our manufacturing and infrastructure companies. First quarter 2014 financing cash flows also include $3.7 million in cash proceeds from the issuance of common stock. In the first quarter of 2014, we began issuing common shares to meet the requirements of our dividend reinvestment and share purchase plan, employee stock ownership plan, and employee stock purchase plan, rather than purchasing shares in the open market.

Net cash used in financing activities of continuing operations in the three months ended March 31, 2013 of $8.6 million reflects $2.5 million in proceeds from short-term borrowings and the issuance of common stock offset by $11.3 million in common and preferred stock dividend payments. On March 1, 2013 OTP used proceeds from a $40.9

million unsecured term loan to fund the redemption of all $25.1 million of the then outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds, and to pay off an intercompany note to the Company that mirrored the Company's $15.5 million in outstanding cumulative preferred shares, which were also redeemed on March 1, 2013.

CAPITAL REQUIREMENTS

2014-2018 Capital Expenditures
The following table shows our 2013 capital expenditures and 2014 through 2018 anticipated capital expenditures and electric utility average rate base:

(in millions)	2013 Actual	2014	2015	2016	2017	2018
Capital Expenditures:						
Electric Segment:						
Transmission		$53	$46	$97	$52	$56
Environmental		82	61	--	--	--
Other		37	38	44	45	46
Total Electric Segment	$149	$172	$145	$141	$97	$102
Manufacturing and Infrastructure Segments	15	23	19	26	20	24
Total Capital Expenditures	$164	$195	$164	$167	$117	$126
Total Electric Utility Average Rate Base		$885	$991	$1,062	$1,120	$1,152

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2014 through 2018 timeframe.

Ashtabula III Wind Farm
OTP has a purchased wind power agreement with the owner of the Ashtabula III wind farm. In connection with this agreement, OTP has the option to purchase the wind farm for approximately $50 million in the 2023 timeframe.

Contractual Obligations
Our contractual obligations reported in the table on page 53 of our Annual Report on Form 10-K for the year ended December 31, 2013 increased $340 million in the first quarter of 2014. Our long-term debt obligations increased $150 million for the years beyond 2018 and our interest obligations on long-term debt increased by $3.9 million for 2014, $15.5 million for 2015 and 2016, $15.5 million for 2017 and 2018 and $155 million for the years beyond 2018 as a result of OTP's February 27, 2014 borrowings under OTP's 2013 Note Purchase Agreement. Our purchase obligations did not increase and OTP entered into no new coal, capacity or energy purchase agreements in the first quarter of 2014.

CAPITAL RESOURCES

Short-Term Debt
On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $150 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 29, 2013 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2017 to October 29, 2018. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. The interest rate being charged under the Second Amended and Restated Credit Agreement prior to the renewal was

LIBOR plus 3.25%. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of the Company's wholly-owned subsidiary, Varistar Corporation, and its material subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our material subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 29, 2013 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2017 to October 29, 2018. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2016 Notes

On December 4, 2009 we issued $100 million of our 9.000% notes due 2016 (the 2016 Notes) under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by the First Supplemental Indenture dated as of July 1, 2009, between us and U.S. Bank National Association (formerly First Trust National Association), as trustee. The 2016 Notes are senior unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year. In November 2013 we purchased and retired, in two separate transactions, $12,933,000 and $34,737,000, respectively, of our outstanding 2016 Notes. The remaining $52,330,000 principal amount of the 2016 Notes outstanding, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016.

2013 Note Purchase Agreement

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, including 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 as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements
On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement dated as of July 29, 2011 (2011 Note Purchase Agreement). OTP used a portion of the proceeds of the 2021 Notes to retire $90 million aggregate principal amount of OTP's 6.63% Senior Notes due December 1, 2011 at maturity and to retire early $10.4 million aggregate principal amount of outstanding pollution control refunding revenue bonds due December 1, 2012. No penalty was paid for the early retirement. The remaining proceeds of the 2021 Notes were used to repay short-term debt of OTP which was issued to fund capital expenditures, to pay fees and expenses related to the debt issuance and to fund a $10 million contribution to the Company's pension plan in January 2012.

OTP also has outstanding its $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including 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 note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Financial Covenants
We were in compliance with the financial covenants in our debt agreements as of March 31, 2014.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Our borrowing agreements are subject to certain financial covenants. Specifically:

Under the Otter Tail Corporation Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Otter Tail Corporation Credit Agreement. As of March 31, 2014 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement was 4.24 to 1.00.

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

Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of March 31, 2014 OTP’s Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 4.04 to 1.00.

Under the 2013 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, each as provided in the 2013 Note Purchase Agreement.

As of March 31, 2014 our interest-bearing debt to total capitalization was 0.48 to 1.00 on a consolidated basis and 0.53 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $9.9 million, but our line of credit borrowing limits are only restricted by $4.5 million of the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2014 BUSINESS OUTLOOK

We are increasing our consolidated diluted earnings per share guidance for 2014 to be in the range of $1.60 to $1.80 from our previously announced range of $1.55 to $1.75. This updated guidance reflects the current mix of businesses owned by us. It considers the cyclical nature of some of our businesses and reflects challenges, as well as our plans and strategies for improving future operating results.

Segment components of our 2014 earnings per share guidance range are as follows:

	Previous 2014 EPS Guidance		Current 2014 EPS Guidance	
	Low	High	Low	High
Electric	$1.19	$1.23	$1.21	$1.25
Manufacturing	$0.29	$0.33	$0.29	$0.33
Plastics	$0.25	$0.29	$0.27	$0.31
Construction	$0.07	$0.11	$0.07	$0.11
Corporate	($0.25)	($0.21)	($0.24)	($0.20)
Total – Continuing Operations	$1.55	$1.75	$1.60	$1.80

Contributing to our updated earnings guidance for 2014 are the following items:

We expect 2014 net income for our Electric segment to increase from our previously issued guidance primarily as a result of the strong first quarter results driven in part by colder than normal weather. Items affecting our 2014 Electric segment earnings guidance compared with 2013 earnings include:

o Rider recovery increases, including environmental riders in Minnesota and North Dakota related to the Big Stone AQCS environmental upgrades while under construction, and

o A decrease in pension costs of approximately $2.0 million as a result of an increase in the discount rate from 4.5% to 5.3%, offset by

o An increase in interest costs as a result of $150 million of fixed rate long term debt put in place in the first quarter of 2014 to finance the Big Stone Plant AQCS and transmission projects, and

o An increase in operating and maintenance costs primarily for increased labor and a planned outage for maintenance at Hoot Lake Plant.

We are maintaining our original 2014 earnings expectations for our Manufacturing segment, which we expect to be unchanged from 2013 results due to the following factors:

- o An increase at BTD due to increased order volume as a result of expanded relationships with customers in recreational vehicle, lawn and garden, industrial and commercial end markets BTD serves, offset by

- o A decrease in earnings from T.O. Plastics due to a reduction in sales of a product the customer will be producing on its own in 2014.

- o Backlog for the manufacturing companies of approximately $115 million for 2014 compared with $97 million one year ago.

We are raising our expectations for 2014 net income for our Plastics segment from our original guidance due to a stronger than expected first quarter.

We are maintaining our original 2014 guidance for our Construction segment. Net income is expected to be higher in 2014 than in 2013 as a result of improved cost control processes in construction management and more selective bidding on projects with the potential for higher margins. Backlog in place for the construction businesses is $85 million for 2014 compared with $100 million one year ago.

Corporate costs are expected to be slightly lower than original guidance as a result of the sale of an investment in tax-credit-qualified low income housing rental property, which was not expected when our original guidance was given, and improved performance in our self-insured health plan.

We review our portfolio of companies at least annually to see where additional opportunities exist to improve our risk profile, improve credit metrics and generate additional sources of cash to support the future capital expenditure plans of our Electric segment.

Critical Accounting Policies Involving Significant Estimates

The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts, percentage-of-completion, warranty and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption “Critical Accounting Policies Involving Significant Estimates” on pages 60 through 64 of our Annual Report on Form 10-K for the year ended December 31, 2013. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2014.

Forward Looking Information - Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

In connection with the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as “may”, “will”, “expect”, “anticipate”, “continue”, “estimate”, “project”, “believes” or similar ex are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act. These forward-looking statements involve risks and uncertainties. Actual results may differ materially from those contemplated by the forward-looking statements due to, among other factors, the risks and uncertainties described in the section entitled “Risk Factors” in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, as well as the various factors described below:

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

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

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

Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of our customers to finance purchases of goods and services, and our financial condition, as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

We made $20.0 million in discretionary contributions to our defined benefit pension plan in January 2014. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.

Declines in projected operating cash flows at any of our reporting units may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

We currently have $7.3 million of goodwill and a $1.1 million indefinite-lived trade name recorded on our consolidated balance sheet related to the acquisition of Foley Company in 2003. Foley net earnings improved $10.4 million between 2012 and 2013. If future expected operating profits do not meet the corporation's projections, the reductions in anticipated cash flows from Foley may indicate its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived intangible assets associated with Foley along with a corresponding charge against earnings.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on us.

Economic conditions could negatively impact our businesses.

If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

Our plans to grow and realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

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

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

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.

We are subject to risks associated with energy markets.

We are subject to risks and uncertainties related to the timing and recovery of deferred tax assets which could have a negative impact on our net income in future periods.

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to our shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

OTP's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO_2) emissions, could affect OTP's operating costs and the costs of supplying electricity to its customers.

Competition from foreign and domestic manufacturers, the price and availability of raw materials and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

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

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

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

A significant failure or an inability to properly bid or perform on projects or contracts by our construction businesses could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

Our construction subsidiaries enter into contracts which could expose them to unforeseen costs and costs not within their control, which may not be recoverable and could adversely affect our results of operations and financial condition.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2014 we had exposure to market risk associated with interest rates because we had $11.9 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.75% under the our $150 million revolving credit facility.

All of our consolidated long-term debt outstanding on March 31, 2014 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

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

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

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, sales volume has been higher and when resin prices are falling, sales volume has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of March 31, 2014 OTP had recognized, on a pretax basis, $39,000 in unrealized gains on open forward contracts for sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP’s forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy sales contracts that are marked to market as of March 31, 2014 are not offset by forward energy purchase contracts. Therefore, the $39,000 in unrealized gains related to these contracts of as of March 31, 2014 are subject to change in subsequent reporting periods or on settlement. These contracts are scheduled for settlement in April and May of 2014. Any fluctuation in the factors used in the fair valuation of these contracts would not result in a significant change to the fair value of the contracts.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities.

Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of March 31, 2014.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on our consolidated balance sheets as of March 31, 2014 and December 31, 2013, and the change in our consolidated balance sheet position from December 31, 2013 to March 31, 2014 and December 31, 2012 to March 31, 2013:

(in thousands)	March 31, 2014	December 31, 2013
Current Asset – Marked-to-Market Gain	$ 1,609	$ 338
Regulatory Asset – Current Deferred Marked-to-Market Loss	3,258	3,008
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	4,994	8,674
Total Assets	9,861	12,020
Current Liability – Marked-to-Market Loss	(8,252)	(11,782)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(533)	(6)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(1,037)	(117)
Total Liabilities	(9,822)	(11,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 39	$ 115

(in thousands)	Year-to-Date March 31, 2014	Year-to-Date March 31, 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	39	81
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 39	$ 81

The $39,000 in recognized but unrealized gains on the forward energy sales contracts marked to market on March 31, 2014 are expected to be realized on settlement as scheduled in April and May of 2014.

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

	Three Months Ended March 31,	
(in thousands)	2014	2013
Net (Loss) Gain on Forward Electric Energy Contracts	$ (4)	$ 226

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of March 31, 2014 was $83,000. As of March 31, 2014 OTP had a net credit risk exposure of $128,000 from three counterparties with investment grade credit ratings. OTP had no exposure at March 31, 2014 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 $128,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after March 31, 2014. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of March 31, 2014, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of March 31, 2014.

During the fiscal quarter ended March 31, 2014, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 28 through 35 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013.

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

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for incentive awards in February 2014 under the Company's 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
January 2014	--	--
February 2014	8,879	$ 27.255
March 2014	--	--
Total	8,879	

Item 6. Exhibits

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

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

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

32.2 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 Financial statements from the Quarterly Report on Form 10-Q of Otter Tail Corporation for the quarter ended March 31, 2014, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Condensed Consolidated Financial Statements.

SIGNATURES

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

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer
(Chief Financial Officer/Authorized Officer)

Dated: May 9, 2014

EXHIBIT INDEX

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