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<br>(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 | Three Months Ended March 31, 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.

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

| (in thousands) | Three Months Ended March 31, 2014 | | Three Months Ended March 31, 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 | % | -- | |

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three months ended March 31, 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 |

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.

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.

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.

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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.

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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:

| (in thousands) | Three Months Ended March 31, 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:

| (in thousands) | Three Months Ended March 31, 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.

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13. Fair Value of Financial Instruments

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

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

Short-Term Debt—The carrying amount approximates fair value because the debt 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 |