

Otter Tail Corp
Form 10-Q
August 09, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the quarterly period ended June 30, 2016

OR

**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 (I.R.S. Employer
incorporation or organization) Identification No.)

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

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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 "

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 "

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 "

Non-accelerated filer "

Smaller reporting company "

(Do not check if a smaller reporting company)

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

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

July 31, 2016 – 38,772,031 Common Shares (\$5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION**Item 1. financial statements****Otter Tail Corporation****Consolidated Balance Sheets**

(not audited)

| (in thousands) | June 30, 2016 | December 31, 2015 |
|--|--------------------------|------------------------------|
| Assets | | |
| Current Assets | | |
| Cash and Cash Equivalents | \$— | \$— |
| Accounts Receivable: | | |
| Trade—Net | 78,677 | 62,974 |
| Other | 7,144 | 9,073 |
| Inventories | 81,396 | 85,416 |
| Unbilled Revenues | 15,909 | 17,869 |
| Income Taxes Receivable | — | 4,000 |
| Regulatory Assets | 17,205 | 18,904 |
| Other | 14,065 | 8,453 |
| Total Current Assets | 214,396 | 206,689 |
| Investments | 8,413 | 8,284 |
| Other Assets | 33,605 | 32,784 |
| Goodwill | 37,572 | 39,732 |
| Other Intangibles—Net | 15,639 | 15,673 |
| Regulatory Assets | 123,706 | 127,707 |
| Plant | | |
| Electric Plant in Service | 1,834,157 | 1,820,763 |
| Nonelectric Operations | 218,007 | 201,343 |
| Construction Work in Progress | 116,848 | 79,612 |
| Total Gross Plant | 2,169,012 | 2,101,718 |
| Less Accumulated Depreciation and Amortization | 740,440 | 713,904 |
| Net Plant | 1,428,572 | 1,387,814 |

| | | |
|--------------|-------------|--------------|
| Total Assets | \$1,861,903 | \$ 1,818,683 |
|--------------|-------------|--------------|

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation**Consolidated Balance Sheets**

(not audited)

| (in thousands, except share data) | June 30, 2016 | December 31, 2015 |
|---|--------------------------|----------------------------------|
| Liabilities and Equity | | |
| Current Liabilities | | |
| Short-Term Debt | \$49,274 | \$80,672 |
| Current Maturities of Long-Term Debt | 52,497 | 52,422 |
| Accounts Payable | 86,210 | 89,499 |
| Accrued Salaries and Wages | 14,774 | 16,182 |
| Accrued Taxes | 10,562 | 14,827 |
| Other Accrued Liabilities | 17,951 | 15,416 |
| Liabilities of Discontinued Operations | 1,868 | 2,098 |
| Total Current Liabilities | 233,136 | 271,116 |
| Pensions Benefit Liability | 95,520 | 104,912 |
| Other Postretirement Benefits Liability | 49,659 | 48,730 |
| Other Noncurrent Liabilities | 24,980 | 23,854 |
| Commitments and Contingencies (note 9) | | |
| Deferred Credits | | |
| Deferred Income Taxes | 217,523 | 207,669 |
| Deferred Tax Credits | 23,678 | 24,506 |
| Regulatory Liabilities | 77,915 | 77,432 |
| Other | 9,580 | 11,595 |
| Total Deferred Credits | 328,696 | 321,202 |
| Capitalization | | |
| Long-Term Debt—Net | 493,804 | 443,846 |
| 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 | — | — |

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| | | |
|--|-----------------|-----------------|
| Common Shares, Par Value \$5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2016—38,703,277 Shares; 2015—37,857,186 Shares | 193,516 | 189,286 |
| Premium on Common Shares | 313,839 | 293,610 |
| Retained Earnings | 132,401 | 126,025 |
| Accumulated Other Comprehensive Loss | (3,648) | (3,898) |
| Total Common Equity | 636,108 | 605,023 |
| Total Capitalization | 1,129,912 | 1,048,869 |
| Total Liabilities and Equity | \$1,861,903 | \$1,818,683 |

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation**Consolidated Statements of Income**

(not audited)

| | Three Months Ended | | Six Months Ended | |
|--|---------------------------|------------|-------------------------|------------|
| | June 30, 2016 | 2015 | June 30, 2016 | 2015 |
| (in thousands, except share and per-share amounts) | | | | |
| Operating Revenues | | | | |
| Electric | \$97,918 | \$90,927 | \$210,903 | \$204,460 |
| Product Sales | 105,564 | 97,226 | 198,821 | 186,534 |
| Total Operating Revenues | 203,482 | 188,153 | 409,724 | 390,994 |
| Operating Expenses | | | | |
| Production Fuel - Electric | 9,990 | 4,183 | 25,690 | 18,782 |
| Purchased Power - Electric System Use | 15,127 | 19,684 | 32,013 | 43,376 |
| Electric Operation and Maintenance Expenses | 38,981 | 37,754 | 78,999 | 75,281 |
| Cost of Products Sold (depreciation included below) | 80,949 | 74,986 | 153,588 | 146,484 |
| Other Nonelectric Expenses | 9,238 | 8,823 | 20,693 | 21,286 |
| Depreciation and Amortization | 18,525 | 14,661 | 36,814 | 29,196 |
| Property Taxes - Electric | 3,589 | 3,262 | 7,268 | 6,764 |
| Total Operating Expenses | 176,399 | 163,353 | 355,065 | 341,169 |
| Operating Income | 27,083 | 24,800 | 54,659 | 49,825 |
| Interest Charges | 7,976 | 7,702 | 15,970 | 15,445 |
| Other Income | 1,532 | 567 | 1,932 | 1,139 |
| Income Before Income Taxes—Continuing Operations | 20,639 | 17,665 | 40,621 | 35,519 |
| Income Tax Expense—Continuing Operations | 5,083 | 4,008 | 10,575 | 8,081 |
| Net Income from Continuing Operations | 15,556 | 13,657 | 30,046 | 27,438 |
| Discontinued Operations | | | | |
| Income (Loss) - net of Income Tax Expense (Benefit) of \$80, (\$1,329), \$100 and (\$2,705) for the respective periods | 119 | (1,992) | 149 | (4,064) |
| Impairment Loss - net of Income Tax Benefit of \$0 for the six months ended June 30, 2015 | — | — | — | (1,000) |
| (Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of (\$280) and \$4,536 for the three and six months ended June 30, 2015 | — | (229) | — | 6,997 |
| Net Income (Loss) from Discontinued Operations | 119 | (2,221) | 149 | 1,933 |
| Net Income | 15,675 | 11,436 | 30,195 | 29,371 |
| Average Number of Common Shares Outstanding—Basic | 38,179,371 | 37,433,318 | 38,058,157 | 37,338,218 |
| Average Number of Common Shares Outstanding—Diluted | 38,321,289 | 37,653,203 | 38,183,249 | 37,558,103 |

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| | | | | |
|---|----------|----------|----------|----------|
| Basic Earnings (Loss) Per Common Share: | | | | |
| Continuing Operations | \$0.41 | \$0.37 | \$0.79 | \$0.74 |
| Discontinued Operations | — | (0.06 |) — | 0.05 |
| | \$0.41 | \$0.31 | \$0.79 | \$0.79 |
| Diluted Earnings (Loss) Per Common Share: | | | | |
| Continuing Operations | \$0.41 | \$0.36 | \$0.79 | \$0.73 |
| Discontinued Operations | — | (0.06 |) — | 0.05 |
| | \$0.41 | \$0.30 | \$0.79 | \$0.78 |
| Dividends Declared Per Common Share | \$0.3125 | \$0.3075 | \$0.6250 | \$0.6150 |

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation**Consolidated Statements of Comprehensive Income**

(not audited)

| | Three Months Ended | | Six Months Ended | |
|--|-------------------------------|----------|-------------------------|----------|
| | June 30, | | June 30, | |
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| Net Income | \$15,675 | \$11,436 | \$30,195 | \$29,371 |
| 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 | — | — | — | (3) |
| Gains (Losses) Arising During Period | 27 | (37) | 100 | (5) |
| Income Tax (Expense) Benefit | (9) | 13 | (35) | 3 |
| Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax Pension and Postretirement Benefit Plans: | | | | |
| Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11) | 155 | 207 | 309 | 411 |
| Income Tax Expense | (63) | (83) | (124) | (165) |
| Pension and Postretirement Benefit Plans – net-of-tax | 92 | 124 | 185 | 246 |
| Total Other Comprehensive Income | 110 | 100 | 250 | 241 |
| Total Comprehensive Income | \$15,785 | \$11,536 | \$30,445 | \$29,612 |

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation**Consolidated Statements of Cash Flows**

(not audited)

| | Six Months Ended | |
|---|-------------------------|----------|
| | June 30, | |
| | 2016 | 2015 |
| (in thousands) | | |
| Cash Flows from Operating Activities | | |
| Net Income | \$30,195 | \$29,371 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | |
| Net Gain from Sale of Discontinued Operations | — | (6,997) |
| Net (Income) Loss from Discontinued Operations | (149) | 5,064 |
| Depreciation and Amortization | 36,814 | 29,196 |
| Deferred Tax Credits | (828) | (939) |
| Deferred Income Taxes | 9,679 | 12,707 |
| Change in Deferred Debits and Other Assets | 2,680 | 11,470 |
| Discretionary Contribution to Pension Plan | (10,000) | (10,000) |
| Change in Noncurrent Liabilities and Deferred Credits | 6,404 | 4,025 |
| Allowance for Equity/Other Funds Used During Construction | (475) | (576) |
| Change in Derivatives Net of Regulatory Deferral | — | (123) |
| Stock Compensation Expense—Equity Awards | 828 | 1,126 |
| Other—Net | (76) | 200 |
| Cash (Used for) Provided by Current Assets and Current Liabilities: | | |
| Change in Receivables | (12,673) | (5,918) |
| Change in Inventories | 4,218 | 3,400 |
| Change in Other Current Assets | (1,043) | 1,913 |
| Change in Payables and Other Current Liabilities | (5,441) | (21,294) |
| Change in Interest and Income Taxes Receivable/Payable | 4,018 | 96 |
| Net Cash Provided by Continuing Operations | 64,151 | 52,721 |
| Net Cash Provided by (Used in) Discontinued Operations | 11 | (10,966) |
| Net Cash Provided by Operating Activities | 64,162 | 41,755 |
| Cash Flows from Investing Activities | | |
| Capital Expenditures | (79,158) | (83,418) |
| Net Proceeds from Disposal of Noncurrent Assets | 1,080 | 2,628 |
| Final Purchase Price Adjustment – BTD-Georgia Acquisition | 1,500 | — |
| Cash Used for Investments and Other Assets | (1,719) | (5,763) |
| Net Cash Used in Investing Activities - Continuing Operations | (78,297) | (86,553) |
| Net Proceeds from Sale of Discontinued Operations | — | 32,765 |
| Net Cash Used in Investing Activities - Discontinued Operations | — | (1,770) |
| Net Cash Used in Investing Activities | (78,297) | (55,558) |
| Cash Flows from Financing Activities | | |
| Change in Checks Written in Excess of Cash | (2,024) | (947) |

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| | | |
|---|----------|----------|
| Net Short-Term Debt (Repayments) Borrowings | (31,398) | 32,186 |
| Proceeds from Issuance of Common Stock – net of Issuance Expenses | 21,645 | 6,848 |
| Payments for Retirement of Capital Stock | (104) | (1,421) |
| Proceeds from Issuance of Long-Term Debt | 50,000 | — |
| Short-Term and Long-Term Debt Issuance Expenses | (59) | (4) |
| Payments for Retirement of Long-Term Debt | (106) | (99) |
| Dividends Paid and Other Distributions | (23,819) | (23,035) |
| Net Cash Provided by Financing Activities – Continuing Operations | 14,135 | 13,528 |
| Net Cash Provided by Financing Activities – Discontinued Operations | — | 322 |
| Net Cash Provided by Financing Activities | 14,135 | 13,850 |
| Net Change in Cash and Cash Equivalents - Discontinued Operations | — | (47) |
| Net Change in Cash and Cash Equivalents | — | — |
| Cash and Cash Equivalents at Beginning of Period | — | — |
| Cash and Cash Equivalents at End of Period | \$— | \$— |

See accompanying condensed notes to consolidated financial statements.

OTTER TAIL CORPORATION

CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed 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, 2015. Because of seasonal and other factors, the earnings for the three- and six-month periods ended June 30, 2016 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following condensed 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, 2015.

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, the price is fixed or determinable and collectability is reasonably assured. 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's (OTP) 2015 forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 815, *Derivatives and Hedging*. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

Agreements Subject to Legally Enforceable Netting Arrangements

The Company does not offset assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet.

Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange (NYMEX).

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2016 and December 31, 2015:

| June 30, 2016 <i>(in thousands)</i> | Level 1 | Level 2 | Level 3 |
|---|---------|---------|------------|
| Assets: | | | |
| Current Assets – Other: | | | |
| Money Market Escrow Accounts – AEV, Inc. and Foley Company Dispositions | \$2,000 | | |
| Investments: | | | |
| Corporate Debt Securities – Held by Captive Insurance Company | | \$4,169 | |
| Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company | | 4,067 | |
| Other Assets: | | | |
| Money Market and Mutual Funds – Nonqualified Retirement Savings Plan | 835 | | |
| Total Assets | \$2,835 | \$8,236 | |
| Liabilities: | | | |
| Other Accrued Liabilities: | | | |
| Derivative Liabilities – Forward Gasoline Purchase Contracts | | \$87 | |
| Total Liabilities | | \$87 | |
| | | | |
| December 31, 2015 <i>(in thousands)</i> | Level 1 | Level 2 | Level 3 |
| Assets: | | | |
| Current Assets – Other: | | | |
| Money Market Escrow Accounts – AEV, Inc. and Foley Company Dispositions | \$2,000 | | |
| Investments: | | | |
| Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company | | \$4,235 | |
| Corporate Debt Securities – Held by Captive Insurance Company | | 3,858 | |
| Other Assets: | | | |
| Money Market and Mutual Funds – Nonqualified Retirement Savings Plan | 196 | | |
| Total Assets | \$2,196 | \$8,093 | |
| Liabilities: | | | |
| Other Accrued Liabilities: | | | |
| Derivative Liabilities – Forward Gasoline Purchase Contracts | | \$199 | |
| Total Liabilities | | \$199 | |

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

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.

Government-Backed and Government-Sponsored Enterprises' and Corporate 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.

Inventories

Inventories consist of the following:

| (in thousands) | June 30, 2016 | December 31, 2015 |
|---------------------------------|------------------|----------------------|
| Finished Goods | \$22,978 | \$ 25,971 |
| Work in Process | 12,133 | 12,821 |
| Raw Material, Fuel and Supplies | 46,285 | 46,624 |
| Total Inventories | \$81,396 | \$ 85,416 |

Goodwill and Other Intangible Assets

On September 1, 2015 Miller Welding & Iron Works, Inc. (BTD-Illinois), a wholly owned subsidiary of BTD Manufacturing, Inc. (BTD), acquired the assets of Impulse Manufacturing, Inc. (Impulse) of Dawsonville, Georgia. The newly acquired business operates under the name BTD-Georgia. Based on the preliminary purchase price allocation, the difference in the fair value of assets acquired and the price paid for Impulse resulted in an initial estimate of acquired goodwill of \$8.2 million. A final determination of the purchase price was agreed to in June 2016 resulting in a \$2.2 million reduction in acquired goodwill in June 2016. See note 2 to the Company's consolidated financial statements for more information.

An assessment of the carrying amounts of the remaining goodwill of the Company's reporting units reported under continuing operations as of December 31, 2015 indicated the fair values are substantially in excess of their respective book values and not impaired.

The following table summarizes changes to goodwill by business segment during 2016:

| (in thousands) | Gross Balance December 31, 2015 | Accumulated Impairments | Balance (net of impairments) December 31, 2015 | Adjustments to Goodwill in 2016 | Balance (net of impairments) June 30, 2016 |
|----------------|---------------------------------------|----------------------------|---|---------------------------------------|---|
| Manufacturing | \$ 20,430 | \$ — | \$ 20,430 | \$ (2,160) | \$ 18,270 |
| Plastics | 19,302 | — | 19,302 | — | 19,302 |
| Total | \$ 39,732 | \$ — | \$ 39,732 | \$ (2,160) | \$ 37,572 |

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC Topic 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement*.

The following table summarizes the components of the Company's intangible assets at June 30, 2016 and December 31, 2015:

| June 30, 2016 (in thousands) | Gross Carrying Amount | Accumulated Amortization | Net Carrying Amount | Remaining Amortization Periods |
|-------------------------------------|--------------------------|-----------------------------|------------------------|--------------------------------------|
|-------------------------------------|--------------------------|-----------------------------|------------------------|--------------------------------------|

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Amortizable Intangible Assets:

| | | | | |
|-------------------------|-----------|----------|-----------|------------------|
| Customer Relationships | \$ 22,491 | \$ 7,310 | \$ 15,181 | 42-230 months |
| Covenant not to Compete | 590 | 164 | 426 | 26 months |
| Other Intangible Assets | 639 | 607 | 32 | 3 months |
| Emission Allowances | — | NA | — | Expensed as used |
| Total | \$ 23,720 | \$ 8,081 | \$ 15,639 | |

December 31, 2015 (in thousands)

Amortizable Intangible Assets:

| | | | | |
|-------------------------|-----------|----------|-----------|------------------|
| Customer Relationships | \$ 21,681 | \$ 6,714 | \$ 14,967 | 48-236 months |
| Covenant not to Compete | 620 | 69 | 551 | 32 months |
| Other Intangible Assets | 639 | 543 | 96 | 9 months |
| Emission Allowances | 59 | NA | 59 | Expensed as used |
| Total | \$ 22,999 | \$ 7,326 | \$ 15,673 | |

The amortization expense for these intangible assets was:

| (in thousands) | Three Months Ended | | Six Months Ended | |
|--|--------------------------|-------|---------------------|-------|
| | June 30, | | June 30, | |
| | 2016 | 2015 | 2016 | 2015 |
| Amortization Expense – Intangible Assets | \$398 | \$244 | \$755 | \$488 |

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

| (in thousands) | 2016 | 2017 | 2018 | 2019 | 2020 |
|--|---------|---------|---------|---------|---------|
| Estimated Amortization Expense – Intangible Assets | \$1,436 | \$1,330 | \$1,264 | \$1,133 | \$1,099 |

Supplemental Disclosures of Cash Flow Information

| (in thousands) | As of June 30, | |
|---|----------------|----------|
| | 2016 | 2015 |
| Noncash Investing Activities: | | |
| Transactions Related to Capital Additions not Settled in Cash | \$17,837 | \$27,267 |

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 lignite 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 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 certain 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 the Company is not required to include CCMC in its 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 commenced with the initial delivery of coal to Coyote Station in 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. If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. Coyote Station started taking delivery of coal and paying for coal and the accumulated development fees and capital charges under the LSA in May 2016. OTP's 35% share of the unrecovered development period costs, development fees and capital charges incurred by CCMC through June 30, 2016 is \$62.5 million. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of June 30, 2016 could be as high as \$62.5 million.

New Accounting Standards

ASU 2014-09—In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Early adoption is permitted, but not any earlier than January 1, 2017. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. The Company is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and evaluating transition options. The Company does not plan to adopt the updated guidance prior to January 1, 2018.

ASU 2015-03—In April 2015, the FASB issued ASU No. 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03), which requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and must be applied retrospectively to balance sheets presented for periods prior to adoption. The Company adopted the updated standards in ASU 2015-03 in the first quarter of 2016. In conjunction with implementing this update, the Company is reclassifying the remaining balance of unamortized line of credit issuance costs from the deferred debit section of its consolidated balance sheet to other assets, eliminating the deferred debits section of its consolidated balance sheet and displaying long-term regulatory assets as a separate line item on its consolidated balance sheet. The effects of applying the guidance in ASU 2015-03 retrospectively to the Company's December 31, 2015 consolidated balance sheet and of the associated reclassification of unamortized line of credit issuance costs are shown in the following table:

| (in thousands) | Previously Stated | Adjustments | Restated |
|--------------------------------------|-------------------|-------------|-----------|
| Other Assets | \$31,108 | \$ 1,676 | \$32,784 |
| Unamortized Debt Expense | 3,897 | (3,897) | — |
| Total Assets | 1,820,904 | (2,221) | 1,818,683 |
| Current Liabilities | | | |
| Current Maturities of Long-Term Debt | 52,544 | (122) | 52,422 |
| Total Current Liabilities | 271,238 | (122) | 271,116 |
| Capitalization | | | |
| Long-Term Debt—Net | 445,945 | (2,099) | 443,846 |
| Total Capitalization | 1,050,968 | (2,099) | 1,048,869 |
| Total Liabilities and Equity | 1,820,904 | (2,221) | 1,818,683 |

ASU 2015-11—In July 2015, the FASB issued ASU No. 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory*, which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update is effective prospectively for fiscal years and interim periods beginning after December 15, 2016, with early adoption permitted. The Company does not expect the adoption of the updated standard to have a material impact on its consolidated financial statements.

ASU 2016-02—In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance

leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous leases guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company is currently reviewing ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and evaluating transition options. The Company does not currently plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

ASU 2016-09—In March 2016, the FASB issued ASU No. 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09), which is intended to improve and simplify accounting and reporting requirements related to stock-based compensation programs. The amendments in ASU 2016-09 will change how companies account for certain aspects of share-based payments to employees. Under the updated standard, excess tax benefits related to vested awards recognized in stockholders' equity under prior guidance will be recognized in the income statement when the awards vest, and the level of shares that can be withheld to cover income taxes on awards to satisfy statutory income tax withholding obligations without triggering liability classification has been increased. The amendments in ASU 2016-09 are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any interim or annual period. The Company is currently evaluating the impact this standard will have on its consolidated financial statements, but does not expect it to be material.

2. Business Combinations and Segment Information

Business Combinations

On September 1, 2015, BT-D-Illinois, a wholly owned subsidiary of BT-D, acquired the assets of Impulse of Dawsonville, Georgia for \$30.8 million in cash. A post-closing reduction in the purchase price of \$1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of \$29.3 million. The acquired business, operating under the name BT-D-Georgia, is a full-service metal fabricator located 30 miles north of Atlanta, Georgia, which offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers. In addition to serving some of BT-D's existing customers from a location closer to the customers' manufacturing facilities, this acquisition provides opportunities for growth in new and existing markets for BT-D with complementing production capabilities that expand the capacity of services offered by BT-D. Pro forma results of operations have not been presented for this acquisition because the effect of the acquisition was not material to the Company.

Below is condensed balance sheet information disclosing the final allocation of the purchase price assigned to each major asset and liability category of BT-D-Georgia:

| | |
|--------------------------|----------|
| (in thousands) | |
| Assets: | |
| Current Assets | \$4,906 |
| Goodwill | 6,083 |
| Other Intangible Assets | 6,270 |
| Other Amortizable Assets | 1,380 |
| Fixed Assets | 13,649 |
| Total Assets | \$32,288 |
| Liabilities: | |
| Current Liabilities | \$2,971 |
| Lease Obligation | 11 |
| Total Liabilities | \$2,982 |
| Cash Paid | \$29,306 |

The assignment of asset values is based on the final purchase price. In the fourth quarter of 2015, the Company elected to early adopt ASU No. 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, which requires that an acquirer in a business combination recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The purchase price adjustment agreed to in June 2016 resulted in a \$2.2 million reduction to the value of acquired goodwill, a \$0.8 million increase in the fair value of acquired customer relationships and a \$0.1 million increase in acquired liabilities. The changes in the value of customer relationships had an insignificant impact on the Company's consolidated net income in 2016 related to a change in amortization expense that would have been

recorded in 2015 had the adjusted asset values been established on acquisition in 2015.

Segment Information

The Company's businesses have been classified into three 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 three segments are: Electric, Manufacturing and Plastics.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a 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, fabrication and painting, and production of material and handling trays and horticultural containers. These businesses have manufacturing facilities in Georgia, 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.

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 2015. All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.5% and 97.3% of its operating revenues for the respective three-month periods ended June 30, 2016 and 2015, and 98.7% and 96.8% of its operating revenues for the respective six-month periods ended June 30, 2016 and 2015.

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three- and six-month periods ended June 30, 2016 and 2015 and total assets by business segment as of June 30, 2016 and December 31, 2015 are presented in the following tables:

Operating Revenue

| (in thousands) | Three Months Ended | | Six Months Ended | |
|---------------------------|--------------------|-----------|------------------|-----------|
| | June 30, 2016 | 2015 | June 30, 2016 | 2015 |
| Electric | \$97,925 | \$90,964 | \$210,919 | \$204,511 |
| Manufacturing | 58,452 | 51,273 | 118,272 | 108,032 |
| Plastics | 47,112 | 45,954 | 80,549 | 78,506 |
| Intersegment Eliminations | (7) | (38) | (16) | (55) |
| Total | \$203,482 | \$188,153 | \$409,724 | \$390,994 |

Interest Charges

| (in thousands) | Three Months Ended | | Six Months Ended | |
|---|--------------------|---------|------------------|----------|
| | June 30, | | June 30, | |
| | 2016 | 2015 | 2016 | 2015 |
| Electric | \$6,156 | \$6,083 | \$12,440 | \$12,204 |
| Manufacturing | 1,006 | 846 | 1,998 | 1,678 |
| Plastics | 279 | 279 | 523 | 525 |
| Corporate and Intersegment Eliminations | 535 | 494 | 1,009 | 1,038 |
| Total | \$7,976 | \$7,702 | \$15,970 | \$15,445 |

Income Tax Expense—Continuing Operations

| (in thousands) | Three Months Ended | | Six Months Ended | |
|----------------|--------------------|---------|------------------|---------|
| | June 30, | | June 30, | |
| | 2016 | 2015 | 2016 | 2015 |
| Electric | \$1,920 | \$1,013 | \$6,532 | \$5,234 |
| Manufacturing | 1,791 | 1,157 | 2,810 | 1,661 |
| Plastics | 2,262 | 2,689 | 3,629 | 3,953 |
| Corporate | (890) | (851) | (2,396) | (2,767) |
| Total | \$5,083 | \$4,008 | \$10,575 | \$8,081 |

Net Income (Loss)

| | Three Months Ended | | Six Months Ended | |
|-------------------------|--------------------|----------|------------------|----------|
| | June 30, | | June 30, | |
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| Electric | \$9,148 | \$8,252 | \$21,686 | \$21,430 |
| Manufacturing | 3,009 | 1,912 | 4,862 | 3,096 |
| Plastics | 3,485 | 4,265 | 5,637 | 6,385 |
| Corporate | (86) | (772) | (2,139) | (3,473) |
| Discontinued Operations | 119 | (2,221) | 149 | 1,933 |
| Total | \$15,675 | \$11,436 | \$30,195 | \$29,371 |

Identifiable Assets

| | June 30, | December 31, |
|----------------|-------------|--------------|
| (in thousands) | 2016 | 2015 |
| Electric | \$1,553,563 | \$1,520,887 |
| Manufacturing | 179,971 | 173,860 |
| Plastics | 89,058 | 81,624 |
| Corporate | 39,311 | 42,312 |
| Total | \$1,861,903 | \$1,818,683 |

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 2016 and 2015.

Major Capital Expenditure Projects

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP's

capitalized cost of the project, excluding Allowance for Funds Used During Construction (AFUDC), as of June 30, 2016 was approximately \$199 million.

Fargo–Monticello 345 kiloVolt (kV) Capacity Expansion 2020 (CapX2020) Project (the Fargo Project)—OTP has invested approximately \$81 million and has a 14.2% ownership interest in the jointly owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345 kV CapX2020 Project (the Brookings Project)—OTP has invested approximately \$26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO approved the Brookings Project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. 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 of MVP's is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. The final segments of this line were energized on March 26, 2015.

The Big Stone South–Brookings MVP and CapX2020 Project—This 345 kV transmission line, currently under construction, will extend approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – MN, a subsidiary of Xcel Energy Inc., jointly developed this project with obligations to have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line is expected to be in service in fall 2017. OTP's capitalized cost of this project as of June 30, 2016 was approximately \$43.0 million, which includes assets that are 100% owned by OTP.

The Big Stone South–Ellendale MVP—This 345 kV transmission line will extend 160 to 170 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU) with obligations of having equal ownership interest in the transmission line portion of the project. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP’s capitalized cost of this project as of June 30, 2016 was approximately \$29.8 million, which includes assets that are 100% owned by OTP.

Recovery of OTP’s major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Minnesota

2016 General Rate Case—On February 16, 2016 OTP filed a request with the MPUC for an increase in revenue recoverable under general rates in Minnesota. In its filing, OTP requested an allowed rate of return on rate base of 8.07% and an allowed rate of return on equity of 10.4% based on an equity ratio of 52.5% of total capital. On February 26, 2016 the Minnesota Department of Commerce (MNDOC) concluded that the filing was complete. On April 14, 2016 the MPUC issued an order approving an interim rate increase of 9.56% to the base rate portion of customers’ bills, as modified and subject to refund. The request and interim rate information is detailed in the table below:

| (\$ in thousands) | Annualized or Test Year | Actual Through June 30, 2016 | |
|--|----------------------------|------------------------------|----------------|
| | | 3 Months Ended | 6 Months Ended |
| Revenue Increase Requested | \$ 19,296 | | |
| Increase Percentage Requested | 9.80 % | | |
| Jurisdictional Rate Base | \$ 483,000 | | |
| Interim Revenue Increase (subject to refund) | \$ 16,816 | \$ 2,850 | \$ 2,850 |

The major components of the requested rate increase are summarized below:

| Revenue Requirement Deficiency Cost Factors (<i>in thousands</i>) | 2016 Test Year Allocation |
|---|---------------------------------|
| Increased Rate Base | \$ 10,000 |
| Increased Expenses | 7,700 |
| Other | 1,596 |

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| | |
|--|-----------|
| Total Requested Revenue Increase | \$ 19,296 |
| Excluded from Interim Rates: Rate Base Effect of Prepaid Pension Asset | (2,480) |
| Approved Interim Revenue Increase (subject to refund) | \$ 16,816 |

Expected dates for next steps in the procedural schedule:

| | |
|--|------------------------|
| Intervenor direct testimony | due August 16, 2016 |
| Public hearings | August 24 and 25, 2016 |
| Evidentiary hearings | October 13-17, 2016 |
| Report of administrative law judge (ALJ) | January 5, 2017 |
| Final order | March 16, 2017 |

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. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%.

Minnesota Conservation Improvement Programs (MNCIP)—OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC. OTP requested approval for recovery of its 2014 MNCIP financial incentive and 2014 program costs not included in base rates from the MPUC in an April 1, 2015 filing. On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of \$3.0 million along with an updated surcharge with an effective date of October 1, 2015. Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of \$4.2 million in 2015. The 2015 MNCIP program resulted in approximately a 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a \$4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

The MNDOC has proposed changes to the MNCIP financial incentive mechanism. On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model will provide utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

The MNDOC opened an additional docket to investigate how investor-owned utilities calculate their avoided costs pertaining to generation capacity, energy, transmission and distribution. Avoided costs are the basis of MNCIP program benefits which going forward will establish OTP's financial incentive. On May 23, 2016 the MNDOC accepted OTP's 2017 avoided costs calculation, but is requiring Minnesota investor-owned utilities to undergo an analysis of transmission and distribution avoided costs for 2018 and 2019 with results to be submitted to the MNDOC by January 31, 2017.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs, plus a return on investment at the level approved in a utility's last general rate case, of new transmission facilities that meet certain criteria. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately \$7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to \$7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016. OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. The proposed rate changes were to be effective on September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The MPUC granted an extension to file initial comments in this docket until November 1, 2016.

Environmental Cost Recovery Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota Environmental Cost Recovery (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 construction work in progress (CWIP) balance at the level approved in OTP's most recent general rate case. The MPUC approved OTP's 2014 ECR rider annual update request on November 24, 2014 with an effective date of December 1, 2014. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis and granted an extension to file initial comments in this docket until November 1, 2016.

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. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

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 along with a return on investment. On March 25, 2015 the NDPSC approved OTP's 2014 annual update to the NDRRA rider, including a change in rate design from an amount per kilowatt-hour consumed to a percentage of a customer's bill, with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of Federal Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the return on equity (ROE) component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%.

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. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case. The NDPSC approved OTP's 2014 annual update to its TCR rider rate on December 17, 2014 with an effective date of January 1, 2015. On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately \$10.2 million for 2016 compared with \$8.5 million for 2015, including costs assessed by the MISO as well as new costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These new costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016.

Environmental Cost Recovery Rider—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. The ECR provides for a current return on CWIP and a return on investment at the level approved in OTP's most recent general rate case. The NDPSC approved OTP's 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant Mercury and Air Toxics Standards (MATS) project costs. On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from \$12.2 million to \$10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its Fuel Clause Adjustment (FCA) rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

South Dakota

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately \$643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

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. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover OTP's South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately \$2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota:

| Rate Rider (<i>in thousands</i>) | Three Months | | Six Months | |
|--|----------------|---------|----------------|---------|
| | Ended June 30, | | Ended June 30, | |
| | 2016 | 2015 | 2016 | 2015 |
| Minnesota | | | | |
| Conservation Improvement Program Costs and Incentives ¹ | \$2,209 | \$1,610 | \$4,715 | \$3,538 |
| Transmission Cost Recovery | 1,133 | 1,212 | 3,409 | 2,827 |
| Environmental Cost Recovery | 3,153 | 2,600 | 6,235 | 5,157 |
| North Dakota | | | | |
| Renewable Resource Adjustment | 1,922 | 1,942 | 3,981 | 3,825 |
| Transmission Cost Recovery | 1,969 | 1,411 | 4,205 | 3,347 |
| Environmental Cost Recovery | 2,771 | 2,765 | 5,582 | 4,921 |
| South Dakota | | | | |
| Transmission Cost Recovery | 411 | 281 | 1,062 | 644 |
| Environmental Cost Recovery | 627 | 519 | 1,260 | 1,023 |
| Conservation Improvement Program Costs and Incentives | 124 | 90 | 283 | 230 |

¹Includes MNCIP costs recovered in base rates.

FERC

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred 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.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may

collect under the MISO Tariff. The complainants are seeking to reduce the 12.38% ROE used in MISO's transmission rates over a 15-month period ending in February 2015 to a proposed 9.15%. On October 16, 2014 the FERC issued an order finding that the current MISO ROE may be unjust and unreasonable and setting the issue for hearing. A non-binding decision by the presiding ALJ was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%. The FERC is expected to issue its order later in 2016. On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issues its order in the ROE complaint proceeding.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67% over a 15-month period ending in May 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearing and hearings were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. The FERC is expected to issue its order in the spring of 2017.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded reductions in revenue of \$1.0 million and \$0.2 million in the three-month periods ended June 30, 2016 and 2015, respectively, and \$1.3 million and \$0.8 million in the six-month periods ended June 30, 2016 and 2015, respectively, and has a \$2.4 million liability on its balance sheet as of June 30, 2016, representing OTP's best estimate of a refund obligation that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, if FERC orders a reduction in the ROE component of the MISO Tariff.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC Topic 980, *Regulated Operations* (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:

| (in thousands) | June 30, 2016 | | | Remaining Recovery/ Refund Period |
|---|-----------------|------------------|------------------|--|
| | Current | Long-Term | Total | |
| Regulatory Assets: | | | | |
| Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹ | \$7,439 | \$96,523 | \$103,962 | see below |
| Deferred Marked-to-Market Losses ¹ | 4,063 | 8,499 | 12,562 | 54 months |
| Conservation Improvement Program Costs and Incentives ² | 1,313 | 6,016 | 7,329 | 24 months |
| Accumulated ARO Accretion/Depreciation Adjustment ¹ | — | 5,911 | 5,911 | asset lives |
| Big Stone II Unrecovered Project Costs – Minnesota | 648 | 2,646 | 3,294 | 58 months |
| North Dakota Renewable Resource Rider Accrued Revenues ² | 1,894 | 684 | 2,578 | 21 months |
| Debt Reacquisition Premiums ¹ | 351 | 1,364 | 1,715 | 195 months |
| Deferred Income Taxes ¹ | — | 1,247 | 1,247 | asset lives |
| MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ² | 616 | 166 | 782 | 24 months |
| Big Stone II Unrecovered Project Costs – South Dakota | 100 | 593 | 693 | 83 months |
| Minnesota Deferred Rate Case Expenses Subject to Recovery ¹ | 458 | — | 458 | 12 months |
| South Dakota Transmission Cost Recovery Rider Accrued Revenues ² | 323 | — | 323 | 12 months |
| Minnesota Renewable Resource Rider Accrued Revenues ² | — | 57 | 57 | 15 months |
| Total Regulatory Assets | \$17,205 | \$123,706 | \$140,911 | |
| Regulatory Liabilities: | | | | |
| Accumulated Reserve for Estimated Removal Costs – Net of Salvage | \$— | \$76,196 | 76,196 | asset lives |
| Refundable Fuel Clause Adjustment Revenues | 2,619 | — | 2,619 | 12 months |
| Revenue for Rate Case Expenses Subject to Refund – Minnesota | 712 | 563 | 1,275 | 22 months |
| Deferred Income Taxes | — | 978 | 978 | asset lives |
| North Dakota Transmission Cost Recovery Rider Accrued Refund | 700 | — | 700 | 12 months |
| Minnesota Environmental Cost Recovery Rider Accrued Refund | 644 | — | 644 | 12 months |
| Minnesota Transmission Cost Recovery Rider Accrued Refund | 642 | — | 642 | 12 months |
| North Dakota Environmental Cost Recovery Rider Accrued Refund | 609 | — | 609 | 12 months |
| South Dakota Environmental Cost Recovery Rider Accrued Refund | 334 | — | 334 | 12 months |
| Other | 31 | 92 | 123 | 210 months |
| MISO Schedule 26/26A Transmission Cost Recovery Rider True-up | — | 86 | 86 | 24 months |
| Total Regulatory Liabilities | \$6,291 | \$77,915 | \$84,206 | |

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| | | | |
|-------------------------------|----------|----------|----------|
| Net Regulatory Asset Position | \$10,914 | \$45,791 | \$56,705 |
|-------------------------------|----------|----------|----------|

¹*Costs subject to recovery without a rate of return.*

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

| (in thousands) | December 31, 2015 | | | Remaining Recovery/ Refund Period |
|---|-------------------|------------------|------------------|--------------------------------------|
| | Current | Long-Term | Total | |
| Regulatory Assets: | | | | |
| Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹ | \$7,439 | \$99,293 | \$106,732 | see below |
| Deferred Marked-to-Market Losses ¹ | 4,063 | 10,530 | 14,593 | 60 months |
| Conservation Improvement Program Costs and Incentives ² | 4,411 | 4,266 | 8,677 | 18 months |
| Accumulated ARO Accretion/Depreciation Adjustment ¹ | — | 5,672 | 5,672 | asset lives |
| Big Stone II Unrecovered Project Costs – Minnesota | 942 | 2,620 | 3,562 | 84 months |
| Debt Reacquisition Premiums ¹ | 351 | 1,539 | 1,890 | 201 months |
| Deferred Income Taxes ¹ | — | 1,455 | 1,455 | asset lives |
| North Dakota Renewable Resource Rider Accrued Revenues ² | — | 1,266 | 1,266 | 15 months |
| MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ² | 698 | 355 | 1,053 | 24 months |
| Big Stone II Unrecovered Project Costs – South Dakota | 100 | 643 | 743 | 89 months |
| Minnesota Transmission Cost Recovery Rider Accrued Revenues ² | 576 | — | 576 | 12 months |
| Minnesota Deferred Rate Case Expenses Subject to Recovery ¹ | 291 | — | 291 | 12 months |
| Minnesota Renewable Resource Rider Accrued Revenues ² | — | 68 | 68 | see below |
| South Dakota Transmission Cost Recovery Rider Accrued Revenues ² | 33 | — | 33 | 12 months |
| Total Regulatory Assets | \$18,904 | \$127,707 | \$146,611 | |
| Regulatory Liabilities: | | | | |
| Accumulated Reserve for Estimated Removal Costs – Net of Salvage | \$— | \$74,948 | \$74,948 | asset lives |
| Refundable Fuel Clause Adjustment Revenues | 1,834 | — | 1,834 | 12 months |
| Revenue for Rate Case Expenses Subject to Refund – Minnesota | — | 1,279 | 1,279 | see below |
| Deferred Income Taxes | — | 1,110 | 1,110 | asset lives |
| Minnesota Environmental Cost Recovery Rider Accrued Refund | 777 | — | 777 | 12 months |
| North Dakota Environmental Cost Recovery Rider Accrued Refund | 321 | — | 321 | 12 months |
| South Dakota Environmental Cost Recovery Rider Accrued Refund | 185 | — | 185 | 12 months |
| North Dakota Transmission Cost Recovery Rider Accrued Refund | 132 | — | 132 | 12 months |
| Deferred Gain on Sale of Utility Property – Minnesota Portion | 5 | 95 | 100 | 216 months |
| North Dakota Renewable Resource Rider Accrued Refund | 68 | — | 68 | 12 months |
| Total Regulatory Liabilities | \$3,322 | \$77,432 | \$80,754 | |
| Net Regulatory Asset Position | \$15,582 | \$50,275 | \$65,857 | |

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 Losses recorded as of June 30, 2016 relate to forward purchases of energy scheduled for delivery through December 2020.

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 project.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of June 30, 2016.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 195 months.

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

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

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 project.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to South Dakota customers as of June 30, 2016.

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 rider rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered over an 18-month period beginning with the establishment of interim rates in April 2016.

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

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates 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 over a 24-month period beginning with the establishment of interim rates in April 2016.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of June 30, 2016.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of June 30, 2016.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of June 30, 2016.

The North Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to North Dakota customers as of June 30, 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of June 30, 2016.

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 expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Open Contract Positions Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The following table shows forward contract fair value positions subject to legally enforceable netting arrangements as of June 30, 2016 and December 31, 2015:

| (in thousands) | June 30, 2016 | December 31, 2015 |
|--|------------------|-------------------------|
| Open Contract Gain Positions Subject to Legally Enforceable Netting Arrangements | \$— | \$— |
| Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements | (14,419) | (16,070) |
| Net Balance Subject to Legally Enforceable Netting Arrangements | \$(14,419) | \$(16,070) |

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in loss positions as of June 30, 2016 and December 31, 2015:

| Loss Position <i>(in thousands)</i> | June 30, 2016 | December 31, 2015 |
|--|------------------|-------------------------|
| Loss Contracts Covered by Deposited Funds or Letters of Credit | \$87 | \$199 |
| Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade ¹ | 14,332 | 15,871 |
| Loss Contracts with No Ratings Triggers or Deposit Requirements | — | — |
| Loss Position | \$14,419 | \$16,070 |
| ¹ Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions. | | |
| Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade | \$14,332 | \$15,871 |
| Offsetting Gains with Counterparties under Master Netting Agreements | — | — |
| Reporting Date Deposit Requirement if Credit Risk Feature Triggered | \$14,332 | \$15,871 |

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

Reconciliation of Common Shareholders' Equity

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| (in thousands) | Par Value, Common Shares | Premium on Common Shares | Retained Earnings | Accumulated Other Comprehensive Income/(Loss) | Total Common Equity |
|---|--------------------------------|-----------------------------------|----------------------|--|---------------------------|
| Balance, December 31, 2015 | \$189,286 | \$293,610 | \$126,025 | \$ (3,898) | \$605,023 |
| Common Stock Issuances, Net of Expenses | 4,249 | 19,486 | | | 23,735 |
| Common Stock Retirements | (19) | (85) | | | (104) |
| Net Income | | | 30,195 | | 30,195 |
| Other Comprehensive Income | | | | 250 | 250 |
| Employee Stock Incentive Plans Expense | | 828 | | | 828 |
| Common Dividends (\$0.625 per share) | | | (23,819) | | (23,819) |
| Balance, June 30, 2016 | \$193,516 | \$313,839 | \$132,401 | \$ (3,648) | \$636,108 |

Shelf Registration

The Company's shelf registration statement filed with the Securities and Exchange Commission on May 11, 2015, under which the Company may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, including common shares of the Company, expires on May 11, 2018. On May 11, 2015, the Company entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which it may offer and sell its common shares from time to time in an At-the-Market offering program through JPMS, as its distribution agent, up to an aggregate sales price of \$75 million.

Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2015 through June 30, 2016:

| | |
|--|------------|
| Common Shares Outstanding, December 31, 2015 | 37,857,186 |
| Issuances: | |
| At-the-Market Offering | 510,139 |
| Automatic Dividend Reinvestment and Share Purchase Plan: | |
| Dividends Reinvested | 93,171 |
| Cash Invested | 69,740 |
| Executive Stock Performance Awards (2013 and 2014 shares earned) | 54,700 |
| Employee Stock Purchase Plan: | |
| Cash Invested | 39,938 |
| Dividends Reinvested | 13,467 |
| Employee Stock Ownership Plan | 23,837 |
| Restricted Stock Issued to Directors | 23,200 |
| Vesting of Restricted Stock Units | 21,025 |
| Directors Deferred Compensation | 542 |
| Retirements: | |
| Shares Withheld for Individual Income Tax Requirements | (3,668) |
| Common Shares Outstanding, June 30, 2016 | 38,703,277 |

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three- and six-month periods ended June 30, 2016 and 2015. 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 basic shares outstanding for the items listed in the following reconciliation:

| | Three Months ended | | Six Months ended | |
|--|--------------------|------------|------------------|------------|
| | June 30 | June 30 | June 30 | June 30 |
| | 2016 | 2015 | 2016 | 2015 |
| Weighted Average Common Shares Outstanding – Basic | 38,179,371 | 37,433,318 | 38,058,157 | 37,338,218 |
| Plus Outstanding Share Awards net of Share Reductions for Unrecognized Stock-Based Compensation Expense and Excess Tax Benefits: | | | | |
| Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers based on Measurement Period-to-Date Performance | 91,381 | 141,540 | 69,133 | 141,540 |

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| | | | | |
|--|------------|------------|------------|------------|
| Underlying Shares Related to Nonvested Restricted Stock | 39,374 | 45,060 | 39,608 | 45,060 |
| Units Granted to Employees | | | | |
| Nonvested Restricted Shares | 7,862 | 31,079 | 12,819 | 31,079 |
| Shares Expected to be Issued Under the Deferred Compensation Program for Directors | 3,301 | 2,206 | 3,532 | 2,206 |
| Total Dilutive Shares | 141,918 | 219,885 | 125,092 | 219,885 |
| Weighted Average Common Shares Outstanding – Diluted | 38,321,289 | 37,653,203 | 38,183,249 | 37,558,103 |

The effect of dilutive shares on earnings per share for the three- and six-month periods ended June 30, 2016 and 2015, 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 period.

7. Share-Based Payments

Stock Incentive Awards

On February 4, 2016 the following stock incentive awards were granted to the Company's executive officers under the 2014 Stock Incentive Plan:

| Award | Shares/ Units Granted | Grant-Date Fair Value per Award | Vesting |
|--|-----------------------------|---------------------------------------|---------------------------------------|
| Stock Performance Awards Granted to Executive Officers | 81,500 | \$ 24.03 | December 31, 2018 |
| Restricted Stock Units Granted to Executive Officers | 22,000 | \$ 28.915 | 25% per year through February 6, 2020 |

On April 11, 2016 the Company's Board of Directors granted the following stock incentive awards to the Company's non-employee directors and key employees under the 2014 Stock Incentive Plan:

| Award | Shares/ Units Granted | Grant-Date Fair Value per Award | Vesting |
|---|-----------------------------|---------------------------------------|------------------------------------|
| Restricted Stock Granted to Nonemployee Directors | 23,200 | \$ 28.66 | 25% per year through April 8, 2020 |
| Restricted Stock Units Granted to Key Employees | 15,800 | \$ 24.00 | 100% on April 8, 2020 |

Under the 2016 performance share award agreements, the aggregate award for performance at target is 81,500 shares. For target performance the Company's executive officers would earn an aggregate of 54,333 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2016 through December 31, 2018, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2016 and the average closing price for the 20 trading days immediately preceding January 1, 2019, respectively. The Company's executive officers would also earn an aggregate of 27,167 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. Actual payment may range from zero to 150% of the target amount, or up to an aggregate of 122,250 common shares. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC Topic 718, *Compensation—Stock Compensation*, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

Under the 2016 performance share award agreements, payment and the amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to certain officers who are parties to executive employment agreements with the Company is to be made at the target amount at the date of any such event. The vesting of these performance share award agreements is accelerated and paid out at target in the event of a change in control, disability or death (and on retirement at or after the age of 62 for certain officers who are parties to executive employment agreements with the Company).

The restricted stock units and shares of restricted stock vest 25% per year from the date of grant, and vesting is accelerated in the event of a change in control, disability, death or retirement, subject to proration on retirement in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards' respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The grant-date fair value of each restricted stock unit granted to an executive officer was the average of the high and low market price per share on the date of grant. The grant-date fair value of each restricted stock unit granted to a key employee that is not an executive officer of the Company was based on the market value of one share of the Company's common stock on the date of grant, discounted for the value of the dividend exclusion on those restricted stock units over the four-year vesting period. The restricted shares granted to the Company's nonemployee directors are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreements. The grant-date fair value of each restricted share was based on the market value of one share of the Company's common stock on the date of grant.

The end of the period over which compensation expense is recognized for the above share-based awards for the individual grantees is the shorter of the indicated vesting period for the respective awards or the date the grantee becomes eligible for retirement as defined in their award agreement.

As of June 30, 2016 the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately \$4.9 million (before income taxes) which will be amortized over a weighted-average period of 2.7 years.

Amounts of compensation expense recognized under the Company's six stock-based payment programs for the three- and six-month periods ended June 30, 2016 and 2015 are presented in the table below:

| (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|-------|---------------------------|---------|
| | 2016 | 2015 | 2016 | 2015 |
| Stock Performance Awards Granted to Executive Officers | \$304 | \$37 | \$841 | \$1,057 |
| Restricted Stock Units Granted to Executive Officers | 64 | 127 | 309 | 380 |
| Restricted Stock Granted to Executive Officers | 22 | 144 | 51 | 301 |
| Restricted Stock Granted to Directors | 128 | 106 | 235 | 204 |
| Restricted Stock Units Granted to Nonexecutive Employees | 81 | 81 | 145 | 147 |
| Employee Stock Purchase Plan (15% discount) | 44 | 45 | 88 | 94 |
| Totals | \$643 | \$540 | \$1,669 | \$2,183 |

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 credit agreements contain restrictions on the payment of cash dividends on a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of June 30, 2016 the Company was in compliance with these financial covenants. See note 10 to the Company's consolidated financial statements on Form 10-K for the year ended December 31, 2015 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 47.5% and 58.1% based on OTP's 2016 capital structure petition approved by order of the MPUC on August 2, 2016. OTP's equity to total capitalization ratio including short-term debt was 52.6% as of June 30, 2016. Total capitalization for OTP cannot currently exceed \$1,123,168,000.

9. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2015 OTP had commitments under contracts, including its share of construction program commitments extending into 2019, of approximately \$89.6 million. At June 30, 2016 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately \$123.1 million.

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 into 2040. In May 2016, OTP entered into a \$3.5 million electric generating capacity purchase agreement for the period June 2017 through May 2019.

OTP has commitments under contracts providing for the purchase and delivery of a significant portion of its current coal requirements. Current coal purchase agreements for Big Stone Plant and Coyote Station expire in 2017 and 2040, respectively. In January 2016, OTP entered into an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant for the period of January 1, 2016 through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment.

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, risks associated with indemnification obligations under divestitures of discontinued operations and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as \$1.0 million.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP has recorded a \$2.4 million liability on its balance sheet as of June 30, 2016, representing OTP's best estimate of a refund obligation that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, if FERC orders a reduction in ROE component of the MISO Tariff.

In 2014, the Environmental Protection Agency (EPA) published proposed standards of performance for CO₂ emissions from new fossil fuel-fired power plants, proposed CO₂ emission guidelines for existing fossil fuel-fired power plants and proposed CO₂ standards of performance for CO₂ emissions from reconstructed and modified fossil fuel-fired power plants under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. All of these rules have been challenged on legal grounds and are currently pending in the D.C. Circuit. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO₂ emission guidelines for existing fossil fuel-fired power plants, pending disposition of petitions for review in the D.C. Circuit and disposition of a petition for a writ of certiorari seeking review by the U.S. Supreme Court, if such a writ is sought. Oral argument before all the judges of the D.C. Circuit (en banc review) is scheduled for September 2016. Uncertainty regarding the status of the rules will likely continue for some time. OTP is actively engaged with the stakeholder processes in each of its states that have continued to move forward with planning efforts during the stay.

Other

The Company is a party to litigation and regulatory enforcement matters arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of June 30, 2016 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of June 30, 2016 and December 31, 2015:

| (in thousands) | Line Limit | In Use on June 30, 2016 | Restricted due to Outstanding Letters of Credit | Available on June 30, 2016 | Available on December 31, 2015 |
|---|------------|----------------------------|---|-------------------------------|--------------------------------------|
| Otter Tail Corporation Credit Agreement | \$ 150,000 | \$ 19,289 | \$ — | \$ 130,711 | \$ 90,334 |
| OTP Credit Agreement | 170,000 | 29,985 | 50 | 139,965 | 148,694 |
| Total | \$ 320,000 | \$ 49,274 | \$ 50 | \$ 270,676 | \$ 239,028 |

Debt Issuances and Retirements

On February 5, 2016 the Company entered into a Term Loan Agreement (the Term Loan Agreement) with the Banks named therein, JPMorgan Chase Bank, N.A., as administrative agent, and JPMS, as Lead Arranger and Book Runner. The Term Loan Agreement provides for an unsecured term loan with an aggregate commitment of \$50 million that the Company may use for purposes of funding working capital, capital expenditures and other corporate purposes of the Company and certain of our subsidiaries. Under the Term Loan Agreement, the Company may, on up to two occasions, enter into additional tranches of term loans in minimum increments of \$10 million, subject to the consent of the lenders and so long as the aggregate amount of outstanding term loans does not exceed \$100 million at any time. Borrowings under the Term Loan Agreement will bear interest at either (1) LIBOR plus 0.90% or (2) the greater of (a) the Prime Rate, (b) the Federal Reserve Bank of New York Rate plus 0.50% and (c) LIBOR multiplied by the Statutory Reserve Rate plus 1%. The applicable interest rate will depend on the Company's election of whether to make the advance a LIBOR advance. The Term Loan Agreement terminates on February 5, 2018. The Term Loan Agreement contains a number of restrictions on the Company, Varistar and certain subsidiaries of Varistar, including restrictions on their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Term Loan Agreement also contains affirmative covenants and events of default, and certain financial covenants. Specifically, the Company must not

permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Term Loan Agreement. The Term Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Term Loan Agreement are guaranteed by Varistar and certain of its subsidiaries.

On February 5, 2016 the Company borrowed \$50 million under the Term Loan Agreement at an interest rate based on the 30 day LIBOR plus 90 basis points and used the proceeds to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2016 and December 31, 2015:

| June 30, 2016 <i>(in thousands)</i> | OTP | Otter Tail Corporation | Otter Tail Corporation Consolidated |
|---|-----------|------------------------|-------------------------------------|
| Short-Term Debt | \$29,985 | \$ 19,289 | \$ 49,274 |
| Long-Term Debt: | | | |
| 9.000% Notes, due December 15, 2016 | | \$ 52,330 | \$ 52,330 |
| Term Loan, LIBOR plus 0.90%, due February 5, 2018 | | 50,000 | 50,000 |
| Senior Unsecured Notes 5.95%, Series A, due August 20, 2017 | \$33,000 | | 33,000 |
| Senior Unsecured Notes 4.63%, due December 1, 2021 | 140,000 | | 140,000 |
| Senior Unsecured Notes 6.15%, Series B, due August 20, 2022 | 30,000 | | 30,000 |
| Senior Unsecured Notes 6.37%, Series C, due August 20, 2027 | 42,000 | | 42,000 |
| Senior Unsecured Notes 4.68%, Series A, due February 27, 2029 | 60,000 | | 60,000 |
| Senior Unsecured Notes 6.47%, Series D, due August 20, 2037 | 50,000 | | 50,000 |
| Senior Unsecured Notes 5.47%, Series B, due February 27, 2044 | 90,000 | | 90,000 |
| North Dakota Development Note, 3.95%, due April 1, 2018 | | 145 | 145 |
| Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021 | | 908 | 908 |
| Total | \$445,000 | \$ 103,383 | \$ 548,383 |
| Less: Current Maturities net of Unamortized Debt Issuance Costs | | 52,497 | 52,497 |
| Unamortized Long-Term Debt Issuance Costs | 1,980 | 102 | 2,082 |
| Total Long-Term Debt net of Unamortized Debt Issuance Costs | \$443,020 | \$ 50,784 | \$ 493,804 |
| Total Short-Term and Long-Term Debt (with current maturities) | \$473,005 | \$ 122,570 | \$ 595,575 |
| | | | |
| December 31, 2015 <i>(in thousands)</i> | OTP | Otter Tail Corporation | Otter Tail Corporation Consolidated |
| Short-Term Debt | \$21,006 | \$ 59,666 | \$ 80,672 |

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Long-Term Debt:

| | | | |
|---|-----------|------------|------------|
| 9.000% Notes, due December 15, 2016 | | \$ 52,330 | \$ 52,330 |
| Senior Unsecured Notes 5.95%, Series A, due August 20, 2017 | \$33,000 | | 33,000 |
| Senior Unsecured Notes 4.63%, due December 1, 2021 | 140,000 | | 140,000 |
| Senior Unsecured Notes 6.15%, Series B, due August 20, 2022 | 30,000 | | 30,000 |
| Senior Unsecured Notes 6.37%, Series C, due August 20, 2027 | 42,000 | | 42,000 |
| Senior Unsecured Notes 4.68%, Series A, due February 27, 2029 | 60,000 | | 60,000 |
| Senior Unsecured Notes 6.47%, Series D, due August 20, 2037 | 50,000 | | 50,000 |
| Senior Unsecured Notes 5.47%, Series B, due February 27, 2044 | 90,000 | | 90,000 |
| North Dakota Development Note, 3.95%, due April 1, 2018 | | 182 | 182 |
| Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021 | | 977 | 977 |
| Total | \$445,000 | \$ 53,489 | \$ 498,489 |
| Less: Current Maturities net of Unamortized Debt Issuance Costs | | 52,422 | 52,422 |
| Unamortized Long-Term Debt Issuance Costs | 2,099 | 122 | 2,221 |
| Total Long-Term Debt net of Unamortized Debt Issuance Costs | \$442,901 | \$ 945 | \$ 443,846 |
| Total Short-Term and Long-Term Debt (with current maturities) | \$463,907 | \$ 113,033 | \$ 576,940 |

11. Pension Plan and Other Postretirement Benefits

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

| (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|--------------------------------|---------|------------------------------|---------|
| | 2016 | 2015 | 2016 | 2015 |
| Service Cost—Benefit Earned During the Period | \$1,381 | \$1,530 | \$2,763 | \$3,030 |
| Interest Cost on Projected Benefit Obligation | 3,521 | 3,347 | 7,043 | 6,672 |
| Expected Return on Assets | (4,866) | (4,592) | (9,733) | (9,192) |
| Amortization of Prior-Service Cost: | | | | |
| From Regulatory Asset | 47 | 47 | 94 | 94 |
| From Other Comprehensive Income ¹ | 1 | 1 | 2 | 2 |
| Amortization of Net Actuarial Loss: | | | | |
| From Regulatory Asset | 1,227 | 1,705 | 2,454 | 3,338 |
| From Other Comprehensive Income ¹ | 32 | 46 | 63 | 86 |
| Net Periodic Pension Cost | \$1,343 | \$2,084 | \$2,686 | \$4,030 |

¹Corporate cost included in Other Nonelectric Expenses.

Cash flows—The Company made discretionary plan contributions totaling \$10,000,000 in January 2016. The Company currently is not required and does not expect to make an additional contribution to the plan in 2016. The Company also made discretionary plan contributions totaling \$10,000,000 in January 2015.

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

| (in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|--------------------------------------|------|------------------------------|------|
| | 2016 | 2015 | 2016 | 2015 |
| Service Cost—Benefit Earned During the Period | \$63 | \$47 | \$126 | \$94 |
| Interest Cost on Projected Benefit Obligation | 417 | 381 | 834 | 762 |
| Amortization of Prior-Service Cost: | | | | |
| From Regulatory Asset | 4 | 4 | 8 | 8 |
| From Other Comprehensive Income ¹ | 10 | 9 | 19 | 19 |

| | | | | |
|--|-------|-------|---------|---------|
| Amortization of Net Actuarial Loss: | | | | |
| From Regulatory Asset | 73 | 84 | 146 | 167 |
| From Other Comprehensive Income ² | 111 | 150 | 223 | 301 |
| Net Periodic Pension Cost | \$678 | \$675 | \$1,356 | \$1,351 |

¹Amortization of Prior Service Costs from Other Comprehensive Income

Charged to:

| | | | | |
|---|-----|-----|-----|-----|
| Electric Operation and Maintenance Expenses | \$4 | \$4 | \$8 | \$8 |
| Other Nonelectric Expenses | 6 | 5 | 11 | 11 |

²Amortization of Net Actuarial Loss from Other Comprehensive Income

Charged to:

| | | | | |
|---|------|------|-------|-------|
| Electric Operation and Maintenance Expenses | \$68 | \$77 | \$136 | \$155 |
| Other Nonelectric Expenses | 43 | 73 | 87 | 146 |

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

| (in thousands) | Three Months | | Six Months | |
|---|----------------|----------------|----------------|----------------|
| | Ended June 30, | Ended June 30, | Ended June 30, | Ended June 30, |
| | 2016 | 2015 | 2016 | 2015 |
| Service Cost—Benefit Earned During the Period | \$305 | \$273 | \$611 | \$648 |
| Interest Cost on Projected Benefit Obligation | 542 | 499 | 1,083 | 1,049 |
| Amortization of Prior-Service Cost: | | | | |
| From Regulatory Asset | 33 | 51 | 66 | 102 |
| From Other Comprehensive Income ¹ | 1 | 2 | 2 | 3 |
| Amortization of Net Actuarial Loss: | | | | |
| From Regulatory Asset | — | (48) | — | — |
| From Other Comprehensive Income ¹ | — | (1) | — | — |
| Net Periodic Postretirement Benefit Cost | \$881 | \$776 | \$1,762 | \$1,802 |
| Effect of Medicare Part D Subsidy | \$(258) | \$(293) | \$(515) | \$(743) |

¹Corporate cost included in Other Nonelectric Expenses.

12. 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:

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of June 30, 2016 and December 31, 2015 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to 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.

| (in thousands) | June 30, 2016 | | December 31, 2015 | |
|---|-----------------|------------|-------------------|------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Short-Term Debt | (49,274) | (49,274) | (80,672) | (80,672) |
| Long-Term Debt including Current Maturities | (546,301) | (641,722) | (496,268) | (561,245) |

14. 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:

| (in thousands) | Three Months Ended | | Six Months Ended | |
|--|--------------------|----------|------------------|----------|
| | June 30, 2016 | 2015 | June 30, 2016 | 2015 |
| Income Before Income Taxes – Continuing Operations | \$20,639 | \$17,665 | \$40,621 | \$35,519 |
| Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%) | 8,049 | 6,889 | 15,842 | 13,852 |
| Increases (Decreases) in Tax from: | | | | |

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| | | | | |
|--|----------|----------|----------|----------|
| Federal Production Tax Credits | (1,885) | (1,656) | (3,571) | (3,710) |
| Corporate Owned Life Insurance | (350) | (40) | (414) | (120) |
| North Dakota Wind Tax Credit Amortization – Net of Federal Taxes | (213) | (213) | (425) | (425) |
| Employee Stock Ownership Plan Dividend Deduction | (157) | (171) | (315) | (343) |
| AFUDC Equity | (150) | (125) | (187) | (225) |
| Section 199 Domestic Production Activities Deduction | (94) | (363) | (198) | (725) |
| Investment Tax Credits | (87) | (143) | (175) | (286) |
| Other Items – Net | (30) | (170) | 18 | 63 |
| Income Tax Expense – Continuing Operations | \$5,083 | \$4,008 | \$10,575 | \$8,081 |
| Effective Income Tax Rate – Continuing Operations | 24.6 % | 22.7 % | 26.0 % | 22.8 % |

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

| (in thousands) | 2016 | 2015 |
|---|-------|-------|
| Balance on January 1 | \$468 | \$222 |
| Increases Related to Tax Positions for Prior Years | — | — |
| Increases Related to Tax Positions for Current Year | 26 | 86 |
| Uncertain Positions Resolved During Year | — | — |
| Balance on June 30 | \$494 | \$308 |

The balance of unrecognized tax benefits as of June 30, 2016 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2016 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of June 30, 2016.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of June 30, 2016, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2012 for federal and North Dakota state income taxes and for tax years prior to 2013 for Minnesota state income taxes.

16. Discontinued Operations

On April 30, 2015 the Company sold Foley Company (Foley), its former water, wastewater, power and industrial construction contractor. On February 28, 2015 the Company sold the assets of AEV, Inc. its former energy and electrical construction contractor. On February 8, 2013 the Company completed the sale of substantially all the assets of its former dock and boatlift company and on November 30, 2012 the Company completed the sale of the assets of its former wind tower manufacturing business. The Company's Construction and Wind Energy segments were eliminated as a result of the sales of Foley, AEV, Inc. and its former wind tower manufacturing business. The financial position, results of operations and cash flows of Foley, AEV, Inc., the Company's former dock and boatlift company and its former wind tower manufacturing business are reported as discontinued operations in the Company's consolidated financial statements. Following are summary presentations of the results of discontinued operations:

| (in thousands) | For the Three Months Ended | | For the Six Months Ended | |
|---|----------------------------|-------------|--------------------------|-----------|
| | June 30, 2016 | 2015 | June 30, 2016 | 2015 |
| Operating Revenues | \$ — | \$ 5,899 | \$ — | \$ 24,623 |
| Operating Expenses | (199) | 9,209 | (249) | 31,350 |
| Goodwill Impairment Charge | — | — | — | 1,000 |
| Operating Income (Loss) | 199 | (3,310) | 249 | (7,727) |
| Other Deductions | — | (11) | — | (42) |
| Income Tax Expense (Benefit) | 80 | (1,329) | 100 | (2,705) |
| Net Income (Loss) from Operations | 119 | (1,992) | 149 | (5,064) |
| (Loss) Gain on Disposition Before Taxes | — | (509) | — | 11,533 |
| Income Tax (Benefit) Expense on Disposition | — | (280) | — | 4,536 |
| Net (Loss) Gain on Disposition | — | (229) | — | 6,997 |
| Net Income (Loss) | \$ 119 | \$ (2,221) | \$ 149 | \$ 1,933 |

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Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of \$2.1 million and \$4.4 million in the three- and six-month periods ended June 30, 2015, respectively.

Following are summary presentations of the major components of liabilities of discontinued operations as of June 30, 2016 and December 31, 2015:

| (in thousands) | June, 2016 | December 31, 2015 |
|--|---------------|----------------------|
| Current Liabilities | \$1,868 | \$ 2,098 |
| Liabilities of Discontinued Operations | \$1,868 | \$ 2,098 |

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

| (in thousands) | 2016 | 2015 |
|--|---------|---------|
| Warranty Reserve Balance, January 1 | \$2,103 | \$2,527 |
| Additional Provision for Warranties Made During the Year | — | — |
| Settlements Made During the Year | — | (115) |
| Decrease in Warranty Estimates for Prior Years | (230) | — |
| Warranty Reserve Balance, June 30 | \$1,873 | \$2,412 |

The warranty reserve balances as of June 30, 2016 relate entirely to products produced by the Company's former wind tower and dock and boatlift manufacturing companies. Certain products sold by the companies carried one to fifteen year warranties. Expenses associated with remediation activities of these companies could be substantial. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company's consolidated statements of income, the Company retains responsibility for warranty claims related to the products they produced prior to the sales of these companies.

For wind towers, the potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. For example, if the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated results of operations and financial condition.

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

Results of Operations

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three- and six-month periods ended June 30, 2016 and 2015, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2016 and our business outlook for the remainder of 2016.

Comparison of the Three Months Ended June 30, 2016 and 2015

Consolidated operating revenues were \$203.5 million for the three months ended June 30, 2016 compared with \$188.2 million for the three months ended June 30, 2015. Operating income was \$27.1 million for the three months ended June 30, 2016 compared with \$24.8 million for the three months ended June 30, 2015. The Company recorded diluted earnings per share from continuing operations of \$0.41 for the three months ended June 30, 2016 compared with \$0.36 for the three months ended June 30, 2015, and total diluted earnings per share of \$0.41 for the three months ended June 30, 2016 compared with \$0.30 for the three months ended June 30, 2015.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three-month periods ended June 30, 2016 and 2015 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

| Intersegment Eliminations (<i>in thousands</i>) | June 30, 2016 | June 30, 2015 |
|--|---------------|---------------|
| Operating Revenues: | | |
| Electric | \$ 7 | \$ 37 |
| Nonelectric | — | 1 |
| Cost of Products Sold | — | 4 |
| Other Nonelectric Expenses | 7 | 34 |

Electric

| (in thousands) | Three Months Ended | | | % Change |
|--|--------------------|----------|----------|-------------|
| | June 30, 2016 | 2015 | Change | |
| Retail Sales Revenues | \$85,985 | \$79,504 | \$6,481 | 8.2 |
| Wholesale Revenues – Company Generation | 859 | 214 | 645 | 301.4 |
| Net Revenue – Energy Trading Activity | — | 58 | (58) | (100.0) |
| Other Revenues | 11,081 | 11,188 | (107) | (1.0) |
| Total Operating Revenues | \$97,925 | \$90,964 | \$6,961 | 7.7 |
| Production Fuel | 9,990 | 4,183 | 5,807 | 138.8 |
| Purchased Power – System Use | 15,127 | 19,684 | (4,557) | (23.2) |
| Other Operation and Maintenance Expenses | 38,981 | 37,754 | 1,227 | 3.2 |
| Depreciation and Amortization | 13,432 | 11,137 | 2,295 | 20.6 |
| Property Taxes | 3,589 | 3,262 | 327 | 10.0 |
| Operating Income | \$16,806 | \$14,944 | \$1,862 | 12.5 |
| Electric kilowatt-hour (kwh) Sales (in thousands) | | | | |
| Retail kwh Sales | 1,048,718 | 993,516 | 55,202 | 5.6 |
| Wholesale kwh Sales – Company Generation | 37,163 | 8,379 | 28,784 | 343.5 |
| Wholesale kwh Sales – Purchased Power Resold | — | 5,517 | (5,517) | (100.0) |
| Heating Degree Days | 455 | 435 | 20 | 4.6 |
| Cooling Degree Days | 133 | 83 | 50 | 60.2 |

The following table shows heating and cooling degree days as a percent of normal:

| | Three Months ended June 30, | | | |
|---------------------|-----------------------------|---|------|---|
| | 2016 | | 2015 | |
| Heating Degree Days | 87.7 | % | 82.7 | % |
| Cooling Degree Days | 125.5 | % | 76.1 | % |

The following table summarizes the estimated impact of weather changes on diluted earnings per share compared with sales under normal weather conditions and to the second quarter of 2015:

| Impact on Diluted Earnings Per Share | Three Months ended June 30, | | |
|--------------------------------------|-----------------------------|-------------------|-----------------|
| | 2016 vs Normal | 2015 vs Normal | 2016 vs 2015 |
| | \$ 0.000 | \$ (0.009) | \$ 0.009 |

The \$6.5 million increase in retail revenue includes:

A \$2.8 million increase in retail revenues related to a 9.56% interim rate increase (subject to refund) implemented in mid-April 2016 in conjunction with Otter Tail Power Company's (OTP's) 2016 Minnesota general rate increase request.

A \$0.7 million increase in Environmental Cost Recovery (ECR) rider revenues due to the recovery of additional investment and costs related to the operation of the air quality control system (AQCS) at Big Stone Plant that was placed in service in December 2015.

A \$0.6 million increase in Transmission Cost Recovery (TCR) rider revenues related to increased investment in transmission plant.

· A \$0.6 million increase in Conservation Improvement Program (CIP) cost recovery and incentive revenues.

A \$0.6 million increase in revenues from the recovery of fuel and purchased power costs mainly due to an increase in the cost of fuel per kwh generated for retail use.

A \$0.6 million increase in revenues related to increased retail kwh sales due to warmer weather in the second quarter of 2016, evidenced by cooling degree days that were 60.2% higher than in the second quarter of 2015 and 125.5% of normal.

A \$0.5 million increase in revenue related to increased kwh sales unrelated to weather, mainly sales to pipeline customers.

Revenue from wholesale electric sales from company-owned generation increased \$0.6 million while fuel costs for wholesale generation increased \$0.5 million, resulting in a \$0.1 million increase in wholesale revenue net of fuel costs.

Other electric revenues increased \$0.9 million as a result of an increase in transmission service charges related to a regional transmission cooperative terminating its integrated transmission agreement (ITA) with Otter Tail Power Company and joining the Southwest Power Pool (SPP) beginning in 2016. Prior to termination, revenues and costs under the ITA were reflected on a net basis in other electric revenue. Under the current arrangement under the Midcontinent Independent System Operator, Inc. (MISO), revenues related to the cooperative's use of OTP's transmission system are included in other electric revenue and costs associated with OTP's use of the cooperative's transmission system are included in operating expense. The \$0.9 million revenue increase above was offset by a \$0.8 million increase in the accrual for an estimated refund obligation that would arise if FERC orders a reduction in the return on equity (ROE) component of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) for revenues billed under the tariff from December 2013 through May 2016. This is related to the non-binding initial decision of the presiding administrative law judge on June 30, 2016 recommending a lower FERC-allowed ROE.

Production fuel costs increased \$5.8 million as a result of a 109.7% increase in kwhs generated from our steam-powered and combustion turbine generators, mainly related to Big Stone Plant being fully operational in the second quarter of 2016 compared to being down for maintenance during the entire second quarter of 2015.

The cost of purchased power to serve retail customers decreased \$4.6 million due to a 14.3% decrease in the cost per kwh purchased, combined with a 10.3% decrease in kwhs purchased. The decreased cost per kwh purchased was driven by lower wholesale energy prices in the second quarter of 2016 compared with the second quarter of 2015. The decrease in kwhs purchased was the result of increased availability and generation from company-owned resources.

Electric operating and maintenance expenses increased \$1.2 million as a result of:

A \$0.8 million increase in transmission service charges related to incurring transmission expenses from SPP participants beginning in 2016 as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the SPP.

A \$0.3 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with federal power plant emission regulations.

A \$0.8 million increase in CIP program expenditures, repair expenses related to June 2016 storms, software licensing and travel expenses.

offset by:

- A \$0.7 million reduction in labor benefit costs mainly related to a decrease in corporate expenses billed to OTP.

Depreciation expense increased \$2.3 million due to the AQCS at Big Stone Plant being placed in service at the end of December 2015 along with increased investment in transmission plant with the final phases of the Fargo-Monticello and Brookings-Southeast Twin Cities 345-kilovolt (kV) transmission lines placed in service in 2015.

The \$0.3 million increase in property tax expense is related to property additions in Minnesota and North Dakota in 2015.

Manufacturing

| (in thousands) | Three Months Ended | | | % |
|-------------------------------|--------------------|---------------|----------|------|
| | June 30, 2016 | June 30, 2015 | Change | |
| Operating Revenues | \$ 58,452 | \$ 51,273 | \$ 7,179 | 14.0 |
| Cost of Products Sold | 43,258 | 39,525 | 3,733 | 9.4 |
| Operating Expenses | 5,261 | 5,224 | 37 | 0.7 |
| Depreciation and Amortization | 4,128 | 2,633 | 1,495 | 56.8 |
| Operating Income | \$ 5,805 | \$ 3,891 | \$ 1,914 | 49.2 |

The \$7.2 million increase in revenues in our Manufacturing segment includes the following:

- Revenues at BTD Manufacturing, Inc. (BTD) increased \$7.8 million, including:

- o Revenues of \$6.5 million in the second quarter of 2016 at BTD-Georgia, the plant we acquired in September 2015.

o A \$3.8 million increase in revenues mainly related to the production of wind tower components at BTD's Illinois plant.

offset by:

o A \$2.5 million decrease in revenues related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased \$0.6 million, reflecting:

o A \$0.9 million decrease in industrial market sales primarily as a result of a continued decline in sales volumes to a customer insourcing product into its own manufacturing facilities.

offset by:

o A \$0.3 million increase in revenues from sales of horticultural containers.

The \$3.7 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased \$3.5 million. This included \$5.7 million in cost of products sold at BTD-Georgia in the second quarter of 2016, offset by a \$2.2 million net decrease in cost of products sold at BTD's other facilities. The \$2.2 million decrease is related to the decrease in sales to recreational and agricultural product manufacturers and to productivity improvements, partially offset by an increase in costs of products sold at BTD's Illinois plant.

Cost of products sold at T.O. Plastics increased \$0.2 million.

Gross margins at BTD were positively impacted in the second quarter of 2016 by changes in customer product mix between quarters.

Operating expenses at BTD increased \$0.4 million, primarily as a result of the BTD-Georgia acquisition.

Operating expenses at T.O. Plastics decreased \$0.3 million as a result of decreases in incentive benefits and selling expenses.

The \$1.5 million increase in depreciation and amortization expenses in our Manufacturing segment includes \$0.8 million at BTD-Georgia in the second quarter of 2016 and a \$0.7 million increase at BTD as a result of placing new assets in service in Minnesota in 2015 and 2016.

Plastics

| (in thousands) | Three Months Ended | | | |
|-------------------------------|--------------------|-----------|-----------|---------|
| | June 30, | | | % |
| | 2016 | 2015 | Change | Change |
| Operating Revenues | \$ 47,112 | \$ 45,954 | \$ 1,158 | 2.5 |
| Cost of Products Sold | 37,691 | 35,465 | 2,226 | 6.3 |
| Operating Expenses | 2,464 | 2,405 | 59 | 2.5 |
| Depreciation and Amortization | 952 | 863 | 89 | 10.3 |
| Operating Income | \$ 6,005 | \$ 7,221 | \$(1,216) | (16.8) |

The \$1.2 million increase in Plastic segment revenues is the result of a 19.2% increase in pounds of polyvinyl chloride (PVC) pipe sold, mostly offset by a 14.0% decrease in the price per pound of pipe sold. The Plastics segment reported increased sales in the western United States, Texas and Missouri. The decline in sales price per pound is due to softening sales prices as a result of lower raw material prices between the quarters. Cost of products sold increased \$2.2 million due to the increase in sales volume, partially offset by a 10.9% decrease in the cost per pound of PVC pipe sold.

Corporate

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

| (in thousands) | Three Months Ended | | | | |
|-------------------------------|--------------------|----------|--------|---------|--|
| | June 30, 2016 | 2015 | Change | % | |
| Operating Expenses | \$ 1,520 | \$ 1,228 | 292 | 23.8 | |
| Depreciation and Amortization | 13 | 28 | (15) | (53.6) | |

Corporate operating expenses increased \$0.3 million between the quarters mainly related to an increase in employee benefit costs.

Interest Charges

The \$0.3 million increase in interest charges in the three months ended June 30, 2016 compared with the three months ended June 30, 2015 is related to a \$50 million increase in the average level of the Company's consolidated variable rate short-term and long-term debt outstanding between the quarters.

Other Income

The \$1.0 million increase in other income in the three months ended June 30, 2016 compared with the three months ended June 30, 2015 is mainly the result of the Company receiving \$0.7 million in benefit proceeds from corporate-owned life insurance and recording \$0.2 million in gains on the sale of low income housing investments in the second quarter of 2016.

Income Taxes – Continuing Operations

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Income tax expense - continuing operations increased \$1.1 million in the three months ended June 30, 2016 compared with the three months ended June 30, 2015, mainly as a result of a \$3.0 million increase in income from continuing operations before income taxes. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three-month periods ended June 30:

| (in thousands) | 2016 | 2015 |
|--|----------|----------|
| Income Before Income Taxes – Continuing Operations | \$20,639 | \$17,665 |
| Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%) | 8,049 | 6,889 |
| Increases (Decreases) in Tax from: | | |
| Federal Production Tax Credits (PTCs) | (1,885) | (1,656) |
| Corporate Owned Life Insurance | (350) | (40) |
| North Dakota Wind Tax Credit Amortization – Net of Federal Taxes | (213) | (213) |
| Employee Stock Ownership Plan Dividend Deduction | (157) | (171) |
| AFUDC Equity | (150) | (125) |
| Section 199 Domestic Production Activities Deduction | (94) | (363) |
| Investment Tax Credits | (87) | (143) |
| Other Items – Net | (30) | |