Otter Tail Corp
Form 10-Q
May 09, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 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 incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

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

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

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 ¨ (Do not check if a smaller reporting company)	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:

April 30, 2016 – 38,116,348 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. financial statements

Otter Tail Corporation

Consolidated Balance Sheets

(not audited)

(in thousands)	March 31, 2016	December 31, 2015
Assets		
Current Assets		
Cash and Cash Equivalents	$—	$ —
Accounts Receivable:		
Trade—Net	73,521	62,974
Other	7,104	9,073
Inventories	85,410	85,416
Unbilled Revenues	16,476	17,869
Income Taxes Receivable	—	4,000
Regulatory Assets	18,636	18,904
Other	8,746	8,453
Total Current Assets	209,893	206,689
Investments	8,411	8,284
Other Assets	33,014	32,784
Goodwill	39,732	39,732
Other Intangibles—Net	15,266	15,673
Regulatory Assets	124,933	127,707
Plant		
Electric Plant in Service	1,824,137	1,820,763
Nonelectric Operations	207,757	201,343
Construction Work in Progress	98,995	79,612
Total Gross Plant	2,130,889	2,101,718
Less Accumulated Depreciation and Amortization	728,781	713,904
Net Plant	1,402,108	1,387,814

Total Assets	$1,833,357	$ 1,818,683

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Balance Sheets

(not audited)

(in thousands, except share data)	**March 31, 2016**	**December 31, 2015**
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	$42,936	$ 80,672
Current Maturities of Long-Term Debt	52,457	52,422
Accounts Payable	89,826	89,499
Accrued Salaries and Wages	13,192	16,182
Accrued Taxes	15,985	14,827
Other Accrued Liabilities	16,401	15,416
Liabilities of Discontinued Operations	2,098	2,098
Total Current Liabilities	232,895	271,116
Pensions Benefit Liability	95,122	104,912
Other Postretirement Benefits Liability	48,923	48,730
Other Noncurrent Liabilities	23,181	23,854
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	213,049	207,669
Deferred Tax Credits	24,092	24,506
Regulatory Liabilities	78,007	77,432
Other	10,567	11,595
Total Deferred Credits	325,715	321,202
Capitalization		
Long-Term Debt—Net	493,801	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	—	—
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares;		

Outstanding, 2016—38,071,418 Shares; 2015—37,857,186 Shares	190,357	189,286
Premium on Common Shares	298,465	293,610
Retained Earnings	128,656	126,025
Accumulated Other Comprehensive Loss	(3,758)	(3,898)
Total Common Equity	613,720	605,023
Total Capitalization	1,107,521	1,048,869
Total Liabilities and Equity	$1,833,357	$ 1,818,683

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Income

(not audited)

	Three Months Ended March 31,	
(in thousands, except share and per-share amounts)	2016	2015
Operating Revenues		
Electric	$112,985	$113,533
Product Sales	93,257	89,308
Total Operating Revenues	206,242	202,841
Operating Expenses		
Production Fuel - Electric	15,700	14,599
Purchased Power - Electric	16,886	23,692
Electric Operation and Maintenance Expenses	40,018	37,527
Cost of Products Sold (depreciation included below)	72,639	71,498
Other Nonelectric Expenses	11,455	12,463
Depreciation and Amortization	18,289	14,535
Property Taxes - Electric	3,679	3,502
Total Operating Expenses	178,666	177,816
Operating Income	27,576	25,025
Interest Charges	7,994	7,743
Other Income	400	572
Income Before Income Taxes – Continuing Operations	19,982	17,854
Income Tax Expense – Continuing Operations	5,492	4,073
Net Income from Continuing Operations	14,490	13,781
Discontinued Operations		
Income (Loss) - net of Income Tax Expense (Benefit) of $20 and ($1,376) for the respective periods	30	(2,072)
Impairment Loss - net of Income Tax Benefit of $0 for the three months ended March 31, 2015	—	(1,000)
Gain on Disposition - net of Income Tax Expense of $4,816 for the three months ended March 31, 2015	—	7,226
Net Income from Discontinued Operations	30	4,154
Net Income	14,520	17,935
Average Number of Common Shares Outstanding—Basic	37,936,943	37,243,118
Average Number of Common Shares Outstanding—Diluted	38,045,208	37,497,881

Basic Earnings Per Common Share:		
Continuing Operations	$0.38	$0.37
Discontinued Operations	—	0.11
	$0.38	$0.48
Diluted Earnings Per Common Share:		
Continuing Operations	$0.38	$0.37
Discontinued Operations	—	0.11
	$0.38	$0.48
Dividends Declared Per Common Share	$0.3125	$0.3075

See accompanying condensed notes to consolidated financial statements

Otter Tail Corporation

Consolidated Statements of Comprehensive Income

(not audited)

	Three Months Ended March 31,	
(in thousands)	2016	2015
Net Income	$ 14,520	$ 17,935
Other Comprehensive Income:		
Unrealized Gains on Available-for-Sale Securities:		
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	—	(3)
Gains Arising During Period	73	32
Income Tax Expense	(26)	(10)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	47	19
Pension and Postretirement Benefit Plans:		
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	154	204
Income Tax Expense	(61)	(82)
Pension and Postretirement Benefit Plans – net-of-tax	93	122
Total Other Comprehensive Income	140	141
Total Comprehensive Income	$ 14,660	$ 18,076

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Cash Flows

(not audited)

	Three Months Ended March 31,	
(in thousands)	2016	2015
Cash Flows from Operating Activities		
Net Income	$14,520	$17,935
Adjustments to Reconcile Net Income to Net Cash Used in Operating Activities:		
Net Gain from Sale of Discontinued Operations	—	(7,226)
Net (Income) Loss from Discontinued Operations	(30)	3,072
Depreciation and Amortization	18,289	14,535
Deferred Tax Credits	(414)	(470)
Deferred Income Taxes	5,330	7,038
Change in Deferred Debits and Other Assets	2,825	3,538
Discretionary Contribution to Pension Plan	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	3,363	41
Allowance for Equity/Other Funds Used During Construction	(95)	(256)
Change in Derivatives Net of Regulatory Deferral	—	(59)
Stock Compensation Expense—Equity Awards	489	623
Other—Net	15	206
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(7,478)	(11,288)
Change in Inventories	6	688
Change in Other Current Assets	(773)	1,270
Change in Payables and Other Current Liabilities	(5,840)	(20,185)
Change in Interest and Income Taxes Receivable/Payable	2,400	(1,549)
Net Cash Provided by (Used in) Continuing Operations	22,607	(2,087)
Net Cash Provided by (Used in) Discontinued Operations	30	(6,263)
Net Cash Provided by (Used in) Operating Activities	22,637	(8,350)
Cash Flows from Investing Activities		
Capital Expenditures	(24,855)	(35,738)
Net Proceeds from Disposal of Noncurrent Assets	682	1,292
Cash Used for Investments and Other Assets	(1,425)	(3,492)
Net Cash Used in Investing Activities - Continuing Operations	(25,598)	(37,938)
Net Proceeds from Sale of Discontinued Operations	—	21,343
Net Cash Used in Investing Activities - Discontinued Operations	—	(1,759)
Net Cash Used in Investing Activities	(25,598)	(18,354)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(666)	(1,236)

Net Short-Term (Repayments) Borrowings	(37,736)	37,798
Proceeds from Issuance of Common Stock – net of Issuance Expenses	3,415	4,697
Payments for Retirement of Capital Stock	(53)	(1,239)
Proceeds from Issuance of Long-Term Debt	50,000	—
Short-Term and Long-Term Debt Issuance Expenses	(58)	(4)
Payments for Retirement of Long-Term Debt	(52)	(49)
Dividends Paid and Other Distributions	(11,889)	(11,498)
Net Cash Provided by Financing Activities – Continuing Operations	2,961	28,469
Net Cash Used in Financing Activities – Discontinued Operations	—	(1,178)
Net Cash Provided by Financing Activities	2,961	27,291
Net Change in Cash and Cash Equivalents - Discontinued Operations	—	(430)
Net Change in Cash and Cash Equivalents	—	157
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$—	$157

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 months ended March 31, 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 (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.

Warranty Reserves

Certain products previously sold by the Company carried one to fifteen year warranties. Although the Company engaged in extensive product quality programs and processes, the Company's warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures. The warranty reserve balances as of March 31, 2016 and December 31, 2015 relate entirely to products that were produced by entities the Company no longer owns prior to the Company selling the assets of those companies. The warranty reserve balance is included in liabilities of discontinued operations. See note 16 to consolidated financial statements.

Fair Value Measurements

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

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

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

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

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

March 31, 2016 *(in thousands)*	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		$4,315	
Corporate Debt Securities – Held by Captive Insurance Company		3,903	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	293		
Total Assets	$2,293	$8,218	
Liabilities:			
Other Accrued Liabilities:			
Derivative Liabilities – Forward Gasoline Purchase Contracts		$107	
Total Liabilities		$107	

December 31, 2015 *(in thousands)*	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)	March 31, 2016	December 31, 2015
Finished Goods	$ 26,440	$ 25,971
Work in Process	12,110	12,821
Raw Material, Fuel and Supplies	46,860	46,624
Total Inventories	$ 85,410	$ 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 $8,244,000.

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) March 31, 2016
Manufacturing	$ 20,430	$ —	$ 20,430	$ —	$ 20,430
Plastics	19,302	—	19,302	—	19,302
Total	$ 39,732	$ —	$ 39,732	$ —	$ 39,732

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*. In the first quarter of 2015, OTP began purchasing emission allowances to apply against sulfur dioxide emissions from Hoot Lake Plant. The cost of unused emission allowances is included in intangible assets on the Company's consolidated balance sheets.

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

March 31, 2016 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods

Amortizable Intangible Assets:				
Customer Relationships	$ 21,681	$ 6,987	$ 14,694	45-233 months
Covenant not to Compete	620	121	499	29 months
Other Intangible Assets	639	575	64	6 months
Emission Allowances	9	NA	9	Expensed as used
Total	$ 22,949	$ 7,683	$ 15,266	

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:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Amortization Expense – Intangible Assets	$ 357	$ 244

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	$1,395	$1,299	$1,230	$1,093	$1,059

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of March 31, 2016	2015
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$24,618	$25,284

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 commences with the initial delivery of coal to Coyote Station (anticipated 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. The LSA was amended on March 16, 2015 to provide, among other things, that during any period between December 31, 2016 and any subsequent date on which CCMC makes initial delivery of coal, the Coyote Station owners will pay the following costs of production as advance payments for lignite: depreciation and amortization charges on capital assets and CCMC's obligations under its loans and leases. In addition, 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. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through March 31, 2016 is $60.3 million. In the event the contract is terminated because regulations or

legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of March 31, 2016 could be as high as $60.3 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.

2. Business Combinations and Segment Information

Business Combinations

On September 1, 2015 BTD-Illinois, a wholly owned subsidiary of BTD, acquired the assets of Impulse of Dawsonville, Georgia for $30.8 million in cash, subject to a post-closing adjustment. Impulse is a full-service metal fabricator located 30 miles north of Atlanta, Georgia. The newly acquired business 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 and is operating under the name BTD-Georgia. In addition to serving some of BTD's existing customers from a location closer to the customers' manufacturing facilities, this acquisition will provide opportunities for growth in new and existing markets for BTD, and complementing production capabilities will expand the capacity of services offered by BTD. 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, at the date of the business combination, disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category of BTD-Georgia:

(in thousands)	
Assets:	
Current Assets	$4,906
Goodwill	8,244
Other Intangible Assets	5,490
Other Amortizable Assets	1,380
Fixed Assets	13,649
Total Assets	$33,669
Liabilities:	
Current Liabilities	$2,852
Lease Obligation	11
Total Liabilities	$2,863
Cash Paid	$30,806

The assignment of asset values is subject to adjustment based on determination of 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 Company currently expects purchase price adjustments subsequent to March 31, 2016, if any, will result in adjustments to acquired goodwill and not result in adjustments to the Company's consolidated net income.

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 97.6% and 96.3% of its operating revenues for the respective three month periods ended March 31, 2016 and 2015 came from sales within the United States.

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

Operating Revenue

	Three Months Ended March 31,	
(in thousands)	2016	2015
Electric	$112,994	$113,547
Manufacturing	59,820	56,759
Plastics	33,437	32,552
Intersegment Eliminations	(9)	(17)
Total	$206,242	$202,841

Interest Charges

	Three Months Ended March 31,	
(in thousands)	2016	2015
Electric	$ 6,284	$ 6,121
Manufacturing	992	832
Plastics	244	246
Corporate and Intersegment Eliminations	474	544
Total	$ 7,994	$ 7,743

Income Taxes

	Three Months Ended March 31,	
(in thousands)	2016	2015
Electric	$ 4,612	$ 4,221
Manufacturing	1,019	504
Plastics	1,367	1,264
Corporate	(1,506)	(1,916)
Total	$ 5,492	$ 4,073

Net Income (Loss)

	Three Months Ended March 31,	
(in thousands)	2016	2015
Electric	$ 12,538	$ 13,178
Manufacturing	1,853	1,184
Plastics	2,152	2,120
Corporate	(2,053)	(2,701)
Discontinued Operations	30	4,154
Total	$ 14,520	$ 17,935

Identifiable Assets

(in thousands)	March 31, 2016	December 31, 2015
Electric	$ 1,528,157	$ 1,520,887
Manufacturing	179,745	173,860
Plastics	87,077	81,624
Corporate	38,378	42,312
Total	$ 1,833,357	$ 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. The capitalized cost of the project, excluding Allowance for Funds Used During Construction (AFUDC) as of March 31,

2016 was approximately $368 million (OTP's 53.9% share was approximately $198 million).

Fargo–Monticello 345 kiloVolt (kV) Capacity Expansion 2020 (CapX2020) Project (the Fargo Project)—OTP has invested approximately $81.8 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 $26.7 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of 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 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 (NSP MN), a subsidiary of Xcel Energy Inc., jointly developed this project. MISO approved this project as an MVP under the MISO Tariff in December 2011. This line is expected to be in service in fall 2017. Construction began on this line in the third quarter of 2015. OTP's capitalized costs on this project as of March 31, 2016 were approximately $29.6 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 is jointly developing this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. A route permit amendment to shift a portion of the route in North Dakota was approved by the NDPSC on December 16, 2015. On June 12, 2015 OTP and MDU entered into agreements to construct the project. This project is expected to be completed in 2019. OTP's capitalized costs on this project as of March 31, 2016 were approximately $20.0 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 increase in annual revenue of approximately $19.3 million, or 9.8%, based on 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. Through this rate case proceeding, OTP is proposing to recover, in base rates, revenue currently subject to recovery under Minnesota TCR and Environmental Cost Recovery (ECR) riders. 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 interim rates, as modified, based on an annualized interim rate increase of $16.8 million, or a 9.56% increase to the base rate portion of customer bills, effective for service rendered on or after April 16, 2016.

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.

The MNDOC has proposed changes to the MNCIP financial incentive mechanism. OTP's position is that minimal changes to the MNCIP financial incentive are required as the incentive will naturally be reduced by lower energy savings potential and lower avoided costs. A hearing date for a decision on this docket has not been set by the MPUC. The MNDOC opened an additional docket to investigate how investor-owned utilities calculate their avoided costs pertaining to generation capacity, energy, transmission and distribution. OTP has responded to information requests and submitted comments and reply comments within this docket.

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 will be filing an update to its TCR rider on or before May 1, 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.

Environmental Cost Recovery Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements include a current return on the project's 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. On April 29, 2016 OTP filed an update to its ECR rider 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 filing.

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 with a return on investment at the level approved in OTP's most recent general rate case. 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 kwh 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 PTC used. The NDPSC held a hearing on this matter on April 27, 2016. The Commission is expected to rule on the requested update before the end of the second quarter of 2016.

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) that will become subject to SPP transmission-related charges when CPEC transmission assets are 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 is primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements.

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. On February 12, 2016, the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016. This update included the recovery of new SPP transmission costs OTP began to incur on January 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 for the three month periods ended March 31:

Rate Rider *(in thousands)*	2016	2015
Minnesota		
Conservation Improvement Program Costs and Incentives[1]	$2,506	$1,928
Transmission Cost Recovery	2,276	1,615
Environmental Cost Recovery	3,082	2,557
North Dakota		
Renewable Resource Adjustment	2,059	1,883
Transmission Cost Recovery	2,236	1,936
Environmental Cost Recovery	2,811	2,156
South Dakota		
Transmission Cost Recovery	651	363
Environmental Cost Recovery	633	504

Conservation Improvement Program Costs and Incentives	159	140

[1]*Includes 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 return on equity (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 current 12.38% ROE used in MISO's transmission rates 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. An initial decision by the presiding administrative law judge (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 the current 12.38% to a proposed 8.67%. The FERC issued an order on June 18, 2015 setting the complaint for hearing and hearings were held the week of February 16, 2016. The ALJ is scheduled to issue an initial decision by June 30, 2016. A decision by the FERC is not expected until 2017.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded reductions in revenue of $0.3 million and $0.6 million in the three month periods ended March 31, 2016 and 2015, respectively, and has a $1.4 million liability on its balance sheet as of March 31, 2016, representing OTP's best estimate of a refund obligation, net of amounts that would be subject to recovery under state jurisdictional TCR riders.

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:

	March 31, 2016			Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$7,439	$97,908	$105,347	see below
Deferred Marked-to-Market Losses[1]	4,063	9,515	13,578	57 months
Conservation Improvement Program Costs and Incentives[2]	2,789	5,065	7,854	27 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	—	5,791	5,791	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	826	2,634	3,460	60 months
North Dakota Renewable Resource Rider Accrued Revenues[2]	1,501	305	1,806	21 months
Debt Reacquisition Premiums[1]	351	1,451	1,802	198 months
Deferred Income Taxes[1]	—	1,351	1,351	asset lives

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	763	227	990	24 months
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	618	718	86 months
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	559	—	559	12 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	245	—	245	12 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	—	68	68	12 months
Total Regulatory Assets	$18,636	$124,933	$143,569	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$—	$75,468	$75,468	asset lives
Refundable Fuel Clause Adjustment Revenues	3,294	—	3,294	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	—	1,403	1,403	24 months
Deferred Income Taxes	—	1,043	1,043	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	982	—	982	12 months
North Dakota Environmental Cost Recovery Rider Accrued Refund	787	—	787	12 months
North Dakota Transmission Cost Recovery Rider Accrued Refund	602	—	602	12 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	342	—	342	12 months
Minnesota Transmission Cost Recovery Rider Accrued Refund	183	—	183	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	93	99	213 months
Total Regulatory Liabilities	$6,196	$78,007	$84,203	
Net Regulatory Asset Position	$12,440	$46,926	$59,366	

[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 Current	Long-Term	Total	Remaining Recovery/ Refund Period
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[2]	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[2]	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	

[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.

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 March 31, 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 March 31, 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 198 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-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

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 that will be subject to recovery after new rates go into effect subsequent to the completion of the rate case.

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 March 31, 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 during the current interim rate period.

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.

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 March 31, 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 March 31, 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 March 31, 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 March 31, 2016.

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 March 31, 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. However, the Company does not net offsetting assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet. The following table shows forward contract positions subject to legally enforceable netting arrangements as of March 31, 2016 and December 31, 2015:

(in thousands)	March 31, 2016	December 31, 2015
Open Contract Gain Positions Subject to Legally Enforceable Netting Arrangements	$ —	$ —
Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements	(18,264)	(16,070)
Net Balance Subject to Legally Enforceable Netting Arrangements	$ (18,264)	$ (16,070)

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

Loss Position *(in thousands)*	March 31, 2016	December 31, 2015
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 107	$ 199
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	18,157	15,871
Loss Contracts with No Ratings Triggers or Deposit Requirements	—	—
Loss Position	$ 18,264	$ 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	$ 18,157	$ 15,871
Offsetting Gains with Counterparties under Master Netting Agreements	—	—
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 18,157	$ 15,871

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

Reconciliation of Common Shareholders' Equity

(in thousands)	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, December 31, 2015	$189,286	$293,610	$126,025	$ (3,898)	$605,023
Common Stock Issuances, Net of Expenses	1,080	4,410			5,490
Common Stock Retirements	(9)	(44)			(53)
Net Income			14,520		14,520
Other Comprehensive Income				140	140
Employee Stock Incentive Plans Expense		489			489
Common Dividends ($0.3125 per share)			(11,889)		(11,889)
Balance, March 31, 2016	$190,357	$298,465	$128,656	$ (3,758)	$613,720

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 March 31, 2016:

Common Shares Outstanding, December 31, 2015	37,857,186
Issuances:	
Executive Stock Performance Awards (2013 and 2014 shares earned)	54,700
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	49,635
Cash Invested	49,281
Employee Stock Purchase Plan:	
Cash Invested	21,819
Dividends Reinvested	7,153
Employee Stock Ownership Plan	23,837
Vesting of Restricted Stock Units	9,675
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(1,868)
Common Shares Outstanding, March 31, 2016	38,071,418

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three month periods ended March 31, 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 for the three month periods ended March 31:

	2016	2015
Weighted Average Common Shares Outstanding – Basic	37,936,943	37,243,118
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	46,885	137,460
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	39,841	42,540
Nonvested Restricted Shares	17,776	49,998
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	3,763	24,277
Potentially Dilutive Stock Options	—	488

Total Dilutive Shares	108,265	254,763
Weighted Average Common Shares Outstanding – Diluted	38,045,208	37,497,881

The effect of dilutive shares on earnings per share for the three month periods ended March 31, 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	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Units Granted to Executive Officers	22,000	$ 28.915	25% per year through February 6, 2020
Stock Performance Awards Granted to Executive Officers	81,500	$ 24.03	December 31, 2018

The vesting of restricted stock units 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 was the average of the high and low market price per share on the date of grant.

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 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 March 31, 2016 the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $4.5 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 month periods ended March 31, 2016 and 2015 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2016	2015
Stock Performance Awards Granted to Executive Officers	$ 537	$ 1,020
Restricted Stock Units Granted to Executive Officers	245	253
Restricted Stock Granted to Executive Officers	29	157
Restricted Stock Granted to Directors	107	98
Restricted Stock Units Granted to Non-Executive Employees	64	66
Employee Stock Purchase Plan (15% discount)	44	49
Totals	$ 1,026	$ 1,643

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 upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of March 31, 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 46.9% and 57.3%. OTP's equity to total capitalization ratio including short-term debt was 52.0% as of March 31, 2016. Total capitalization for OTP cannot currently exceed $1,056,300,000.

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 March 31, 2016 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately $102.9 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. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2016, 2017 and 2040. 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 $1.4 million liability on its balance sheet as of March 31, 2016, representing OTP's best estimate of a refund obligation, net of amounts that would be subject to recovery under state jurisdictional TCR riders.

In 2014, the 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, essentially requiring that such plants install updated control technology when constructing, modifying or reconstructing to reduce their emissions. The EPA published final rules for each of these proposals on October 23, 2015. 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 the D.C. Circuit is scheduled for June 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 March 31, 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 March 31, 2016 and December 31, 2015:

(in thousands)	Line Limit	In Use on March 31, 2016	Restricted due to Outstanding Letters of Credit	Available on March 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 150,000	$ 20,880	$ —	$ 129,120	$ 90,334
OTP Credit Agreement	170,000	22,056	—	147,944	148,694
Total	$ 320,000	$ 42,936	$ —	$ 277,064	$ 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 March 31, 2016 and December 31, 2015:

March 31, 2016 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$22,056	$ 20,880	$ 42,936
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		163	163
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021		944	944
Total	$445,000	$ 103,437	$ 548,437
Less: Current Maturities net of Unamortized Debt Issuance Costs		52,457	52,457
Unamortized Long-Term Debt Issuance Costs	2,039	140	2,179
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$442,961	$ 50,840	$ 493,801
Total Short-Term and Long-Term Debt (with current maturities)	$465,017	$ 124,177	$ 589,194

December 31, 2015 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$21,006	$ 59,666	$ 80,672
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:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Service Cost—Benefit Earned During the Period	$1,382	$1,500
Interest Cost on Projected Benefit Obligation	3,522	3,325
Expected Return on Assets	(4,867)	(4,600)
Amortization of Prior-Service Cost:		
From Regulatory Asset	47	47
From Other Comprehensive Income[1]	1	1
Amortization of Net Actuarial Loss:		
From Regulatory Asset	1,227	1,633
From Other Comprehensive Income[1]	31	40
Net Periodic Pension Cost	$1,343	$1,946

[1]*Corporate 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:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Service Cost—Benefit Earned During the Period	$ 63	$ 47
Interest Cost on Projected Benefit Obligation	417	381
Amortization of Prior-Service Cost:		
From Regulatory Asset	4	4
From Other Comprehensive Income[1]	9	10
Amortization of Net Actuarial Loss:		
From Regulatory Asset	73	83
From Other Comprehensive Income[2]	112	151

Net Periodic Pension Cost	$ 678	$ 676
[1]Amortization of Prior Service Costs from Other Comprehensive Income Charged to:		
Electric Operation and Maintenance Expenses	$ 4	$ 4
Other Nonelectric Expenses	5	6
[2]Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:		
Electric Operation and Maintenance Expenses	$ 68	$ 78
Other Nonelectric Expenses	44	73

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:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Service Cost—Benefit Earned During the Period	$ 306	$ 375
Interest Cost on Projected Benefit Obligation	541	550
Amortization of Prior-Service Cost:		
From Regulatory Asset	33	51
From Other Comprehensive Income[1]	1	1
Amortization of Net Actuarial Loss:		
From Regulatory Asset	—	48
From Other Comprehensive Income[1]	—	1
Net Periodic Postretirement Benefit Cost	$ 881	$ 1,026
Effect of Medicare Part D Subsidy	$ (257)	$ (450)

[1] Corporate 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 March 31, 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.

	March 31, 2016		December 31, 2015	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Short-Term Debt	(42,936)	(42,936)	(80,672)	(80,672)
Long-Term Debt including Current Maturities	(546,258)	(623,484)	(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 for the three month periods ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Income Before Income Taxes – Continuing Operations	$ 19,982	$ 17,854
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	7,793	6,963
Increases (Decreases) in Tax from:		

Federal Production Tax Credits	(1,686	)	(2,054	)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212	)	(212	)
Section 199 Domestic Production Activities Deduction	(104	)	(362	)
Employee Stock Ownership Plan Dividend Deduction	(158	)	(172	)
Corporate Owned Life Insurance	(64	)	(80	)
AFUDC Equity	(37	)	(100	)
Other Items – Net	(40	)	90	
Income Tax Expense – Continuing Operations	$ 5,492		$ 4,073	
Effective Income Tax Rate – Continuing Operations	27.5	%	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	16	44
Uncertain Positions Resolved During Year	—	—
Balance on March 31	$484	$266

The balance of unrecognized tax benefits as of March 31, 2016 would reduce the Company’s effective tax rate if recognized. The total amount of unrecognized tax benefits as of March 31, 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 March 31, 2016.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of March 31, 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 boat lift 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 for the three month periods ended March 31:

(in thousands)	2016	2015
Operating Revenues	$—	$18,724
Operating Expenses	(50)	22,141
Goodwill Impairment Charge	—	1,000
Operating Income (Loss)	50	(4,417)
Other Deductions	—	(31)
Income Tax Expense (Benefit)	20	(1,376)
Net Income (Loss) from Operations	30	(3,072)
Gain on Disposition Before Taxes	—	12,042
Income Tax Expense on Disposition	—	4,816
Net Gain on Disposition	—	7,226
Net Income	$30	$4,154

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 percentage of completion was based on the ratio of costs incurred to total estimated costs on construction projects in progress. In the first quarter of 2015, an increase in estimated costs in excess of previous period cost estimates on one large job in progress at Foley resulted in pretax charges of $2.3 million. Foley also recorded a $1.0 million goodwill impairment charge based on adjustments to its carrying value in the first quarter of 2015.

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

(in thousands)	March 31, 2016	December 31, 2015

Current Liabilities	$ 2,098	$ 2,098
Liabilities of Discontinued Operations	$ 2,098	$ 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	—	(6)
Decrease in Warranty Estimates for Prior Years	—	—
Warranty Reserve Balance, March 31	$2,103	$2,521

The warranty reserve balances as of March 31, 2016 relate entirely to products produced by the Company's former wind tower and dock and boatlift manufacturing companies. Expenses associated with remediation activities of these companies could be substantial. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company's consolidated statements of income, the Company retains responsibility for warranty claims related to the products they produced prior to the sales of these companies.

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

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

Results of Operations

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three months ended March 31, 2016 and 2015, followed by a discussion of changes in our consolidated financial position during the three months ended March 31, 2016 and our business outlook for the remainder of 2016.

Comparison of the Three Months Ended March 31, 2016 and 2015

Consolidated operating revenues were $206.2 million for the three months ended March 31, 2016 compared with $202.8 million for the three months ended March 31, 2015. Operating income was $27.6 million for the three months ended March 31, 2016 compared with $25.0 million for the three months ended March 31, 2015. The Company recorded diluted earnings per share from continuing operations of $0.38 for the three months ended March 31, 2016 compared with $0.37 for the three months ended March 31, 2015, and total diluted earnings per share of $0.38 for the three months ended March 31, 2016 compared with $0.48 for the three months ended March 31, 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 March 31, 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 *(in thousands)*	March 31, 2016	March 31, 2015
Operating Revenues:		
Electric	$ 9	$ 14
Nonelectric	—	3
Other Nonelectric Expenses	9	17

Electric

	Three Months Ended March 31,	%

(in thousands)	2016	2015	Change	Change
Retail Sales Revenues	$100,655	$103,614	$(2,959)	(2.9)
Wholesale Revenues – Company Generation	911	1,060	(149)	(14.1)
Net Revenue – Energy Trading Activity	—	127	(127)	(100.0)
Other Revenues	11,428	8,746	2,682	30.7
Total Operating Revenues	$112,994	$113,547	$(553)	(0.5)
Production Fuel	15,700	14,599	1,101	7.5
Purchased Power – System Use	16,886	23,692	(6,806)	(28.7)
Other Operation and Maintenance Expenses	40,018	37,527	2,491	6.6
Depreciation and Amortization	13,483	11,064	2,419	21.9
Property Taxes	3,679	3,502	177	5.1
Operating Income	$23,228	$23,163	$65	0.3
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	1,373,199	1,361,683	11,516	0.8
Wholesale kwh Sales – Company Generation	43,410	36,097	7,313	20.3
Wholesale kwh Sales – Purchased Power Resold	—	20	(20)	(100.0)
Heating Degree Days	2,799	3,324	(525)	(15.8)

The $3.0 million decrease in retail revenue includes:

- A $5.5 million decrease in revenues from the recovery of fuel and purchased power costs mainly due to a 29.3% decrease in the price per kwh of electricity purchased for retail customers.

- A $2.2 million decrease in revenues related to lower kwh sales due to milder weather in the first quarter of 2016, reflective of a 15.8% decrease in heating degree days between the quarters.

- A $1.0 million decrease in revenues due to lower sales to residential customers in North Dakota and Minnesota and lower sales to commercial customers in North Dakota.

offset by:

- A $2.4 million increase in revenues related to a 48.1% increase in kwh sales to industrial customers, mainly pipeline operators.

- A $1.3 million increase in Environmental Costs Recovery (ECR) rider revenue 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 $1.2 million increase in Transmission Costs Recovery (TCR) rider revenues related to increased investment in transmission plant.

- A $0.6 million net increase in Conservation Improvement Program (CIP) cost recovery and incentive revenues mainly related to recovery of increased program costs.

- A $0.2 million increase in North Dakota Renewable Resource Adjustment (NDRRA) rider revenues related to a 19.9% reduction in kwh generation from company-owned wind turbines eligible for federal Production Tax Credits (PTCs) due to lower wind speeds in the first quarter of 2016, which resulted in fewer PTC-related benefits being passed back to customers through the NDRRA in the first quarter of 2016.

Other electric revenues increased $2.7 million as a result of an increase in Midcontinent Independent System Operator, Inc. (MISO) accrued transmission tariff revenues related to increased investment in regional transmission lines and driven in part by returns on and recovery of Capacity Expansion 2020 (CapX2020) and MISO designated Multi-Value Project (MVP) investment costs and operating expenses.

Production fuel costs increased $1.1 million as a result of a 4.9% increase in kwhs generated from OTP's steam-powered and combustion turbine generators. Coyote Station generated more kwhs compared to the first quarter of 2015 when it was operating at reduced load due to a December 2014 boiler feed pump failure and ensuing fire. Big Stone Plant generated more kwhs in the first quarter of 2016 compared to the first quarter of 2015 when it was shut down for a planned maintenance outage during March 2015.

The cost of purchased power to serve retail customers decreased $6.8 million due to a 29.3% decrease in the cost per kwh purchased. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from the milder winter weather in 2016 and lower prices for natural gas used in the generation of electricity in the first quarter of 2016 compared with the first quarter of 2015.

Electric operating and maintenance expenses increased $2.5 million as a result of:

- A $1.0 million expense for first quarter 2016 transmission costs related to a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the Southwest Power Pool.

- A $0.9 million increase in MISO transmission service charges related to increasing investments in regional CapX2020 and MISO-designated MVP transmission projects.

- A $0.8 million increase in CIP program expenditures.

- A $0.6 million increase in pollution control reagent expenses incurred to comply with federal emissions laws and regulations and for the initial operations of Big Stone Plant's AQCS in the first quarter of 2016.

- A $1.0 million increase in expenditures for vegetation maintenance and other items.

offset by:

- A $1.2 million net reduction in generation plant maintenance costs, mainly related to Big Stone Plant incurring higher maintenance costs in the first quarter of 2015 while offline for planned maintenance in March 2015.

- A $0.6 million reduction in labor benefit costs related to a decrease in corporate expenses billed to OTP.

Depreciation expense increased $2.4 million mainly 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 near the end of the first quarter of 2015.

The $0.2 million increase in property tax expense is related to property additions in Minnesota and North Dakota in 2015.

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Manufacturing

(in thousands)	Three Months Ended March 31, 2016	2015	Change	% Change
Operating Revenues	$ 59,820	$ 56,759	$ 3,061	5.4
Cost of Products Sold	46,055	45,699	356	0.8
Operating Expenses	6,074	5,938	136	2.3
Depreciation and Amortization	3,836	2,592	1,244	48.0
Operating Income	$ 3,855	$ 2,530	$ 1,325	52.4

The $3.1 million increase in revenues in our Manufacturing segment includes the following:

· Revenues at BTD Manufacturing, Inc. (BTD), increased $3.9 million, including:

o Revenue of $7.8 million earned in the first quarter of 2016 at BTD-Georgia, which was acquired in September 2015.

o A $1.7 million increase in revenues mainly related to the production of wind tower components.

o A $1.4 million increase in revenues from tooling production and sales.

Offset by:

o A $6.4 million decrease in revenue related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.

o A $0.6 million decrease in revenue from sales of scrap metal due to a reduction in scrap metal prices.

· Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased $0.8 million, including:

o A $1.0 million decrease in industrial market sales primarily as a result of a customer insourcing product into its own manufacturing facilities.

Offset by:

- A $0.3 million increase in revenue from sales of horticultural containers.

The $0.4 million increase in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $1.1 million. This included $6.6 million in cost of products sold at BTD-Georgia in the first quarter of 2016, offset by a $5.5 million net decrease in cost of products sold at BTD's other facilities. The $5.5 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 decreased $0.7 million related to the decrease in sales.

The $0.1 million increase in operating expenses in our Manufacturing segment includes the following:

- Operating expenses at BTD increased $0.3 million, primarily due to $0.8 million in operating expenses incurred at BTD-Georgia in the first quarter of 2016, offset by a $0.5 million decrease in operating expenses at BTD's other facilities as a result of reductions in labor-related costs.

- Operating expenses at T.O. Plastics decreased $0.2 million as a result of a decrease in selling expenses.

The $1.2 million increase in depreciation and amortization expenses in our Manufacturing segment includes $0.8 million in depreciation and amortization expenses at BTD-Georgia in the first quarter of 2016 and a $0.4 million increase in depreciation and amortization expenses at BTD's other facilities as a result of placing new assets in service in Minnesota.

Plastics

(in thousands)	Three Months Ended March 31, 2016	2015	Change	% Change
Operating Revenues	$ 33,437	$ 32,552	$ 885	2.7
Cost of Products Sold	26,584	25,799	785	3.0
Operating Expenses	2,148	2,290	(142)	(6.2)
Depreciation and Amortization	958	848	110	13.0
Operating Income	$ 3,747	$ 3,615	$ 132	3.7

The $0.9 million increase in Plastic segment revenues is the result of an 18.5% increase in pounds of polyvinyl chloride (PVC) pipe sold, mostly offset by a 13.3% decrease in the price per pound of pipe sold. The Plastics segment reported increased sales in the southwest and central regions of the United States. Cost of products sold increased $0.8 million due to the increase in sales volume, mostly offset by a 13.1% decrease in the cost per pound of PVC pipe sold. The decreases in revenue per pound of pipe sold and costs per pound of pipe sold are both related to a decrease in resin costs between the quarters.

Corporate

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

(in thousands)	Three Months Ended March 31, 2016	2015	Change	% Change
Operating Expenses	$ 3,242	$ 4,252	$(1,010)	(23.8)
Depreciation and Amortization	12	31	(19)	(61.3)

Corporate operating expenses decreased $1.0 million, mainly due to:

- A $1.3 million decrease in labor and benefit costs related to a reduction in employee count and lower stock compensation and performance incentive expenses.

- A $0.5 million reduction in contracted services.

offset by:

- A $0.8 million decrease in corporate costs allocated to the Electric segment mainly related to the reductions in labor and benefit costs.

Interest Charges

The $0.3 million increase in interest charges in the three months ended March 31, 2016 compared with the three months ended March 31, 2015 is related to a $57 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 $0.2 million decrease in other income in the three months ended March 31, 2016 compared with the three months ended March 31, 2015 is due to a reduction in allowance for funds used during construction at OTP related to increased use of lower-cost short-term borrowings in the first quarter of 2016 compared with the first quarter of 2015.

Income Taxes – Continuing Operations

-

Income tax expense - continuing operations increased $1.4 million in the three months ended March 31, 2016 compared with the three months ended March 31, 2015 as a result of a $2.1 million increase in income from continuing operations before income taxes and a $0.4 million reduction in federal PTCs earned between the quarters. 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 March 31, 2016 and 2015:

	Three Months Ended March 31,	
(in thousands)	2016	2015
Income Before Income Taxes – Continuing Operations	$ 19,982	$ 17,854
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	7,793	6,963
Increases (Decreases) in Tax from:		
Federal Production Tax Credits	(1,686)	(2,054)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212)	(212)
Section 199 Domestic Production Activities Deduction	(104)	(362)
Employee Stock Ownership Plan Dividend Deduction	(158)	(172)
Corporate Owned Life Insurance	(64)	(80)
AFUDC Equity	(37)	(100)
Other Items – Net	(40)	90
Income Tax Expense – Continuing Operations	$ 5,492	$ 4,073
Effective Income Tax Rate – Continuing Operations	27.5 %	22.8 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs decreased 19.9% in the three months ended March 31, 2016 compared with the three months ended March 31, 2015 due to lower wind speeds. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Discontinued Operations

On April 30, 2015 we sold Foley Company (Foley), our former water, wastewater, power and industrial construction contractor. On February 28, 2015 we sold the assets of AEV, Inc. our former energy and electrical construction contractor, resulting in a first quarter 2015 net gain on the sale of $7.2 million. On February 8, 2013 we completed the sale of substantially all the assets of our former dock and boatlift company and on November 30, 2012 we completed the sale of the assets of our former wind tower manufacturing business. Our Construction and Wind Energy segments were eliminated as a result of the sales of Foley, AEV, Inc. and our former wind tower manufacturing business. The financial position, results of operations and cash flows of Foley, AEV, Inc., our former dock and boatlift company and our former wind tower manufacturing business are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the three month periods ended March 31:

(in thousands)	2016	2015
Operating Revenues	$—	$18,724
Operating Expenses	(50)	22,141
Goodwill Impairment Charge	—	1,000
Operating Income (Loss)	50	(4,417)
Other Deductions	—	(31)
Income Tax Expense (Benefit)	20	(1,376)
Net Income (Loss) from Operations	30	(3,072)
Gain on Disposition Before Taxes	—	12,042
Income Tax Expense on Disposition	—	4,816
Net Gain on Disposition	—	7,226
Net Income	$30	$4,154

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 percentage of completion was based on the ratio of costs incurred to total estimated costs on construction projects in progress. In the first quarter of 2015, an increase in estimated costs in excess of previous period cost estimates on one large job in progress at Foley resulted in pretax charges of $2.3 million. Foley also recorded a $1.0 million goodwill impairment charge based on adjustments to its carrying value in the first quarter of 2015.

Financial Position

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

(in thousands)	Line Limit	In Use on March 31, 2016	Restricted due to Outstanding Letters of Credit	Available on March 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 150,000	$ 20,880	$ —	$ 129,120	$ 90,334
OTP Credit Agreement	170,000	22,056	—	147,944	148,694
Total	$ 320,000	$ 42,936	$ —	$ 277,064	$ 239,028

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2015 we filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 11, 2018. On May 11, 2015, we entered into a Distribution Agreement with J.P. Morgan Securities LLC (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million through an At-the-Market offering program. No shares were issued under this program in the first quarter of 2016.

Equity or debt financing will be required in the period 2016 through 2020 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 8 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On January 28, 2016 our board of directors increased the quarterly dividend from $0.3075 to $0.3125 per common share.

Cash provided by operating activities of continuing operations was $22.6 million for the three months ended March 31, 2016 compared with cash used in operating activities of $2.1 million for the three months ended March 31, 2015. Contributing to the $24.7 million increase in cash provided by operating activities of continuing operations between the quarters was a $19.4 million decrease in cash used for working capital items and a $4.5 million increase in net income from continuing operations net of non-cash depreciation and amortization expenses. The $19.4 million decrease in cash used for working capital items between the periods includes:

- A $7.4 million decrease in cash used for accounts payable related to operating activities at OTP between the quarters.

- A $6.3 million decrease in cash used for accounts payable in the Plastics segment between the quarters, due in part to lower resin costs.

- A $4.4 million decrease in cash used for accounts receivable related to operating activities at OTP between the quarters.

In continuing operations, net cash used in investing activities was $25.6 million for the three months ended March 31, 2016 compared with $37.9 million for the three months ended March 31, 2015. The $12.3 million decrease in cash used for investing activities includes:

- An $8.3 million reduction in capital expenditures at OTP as the Big Stone Plant AQCS was under construction in the first quarter of 2015 and in service in the first quarter of 2016.

- A $1.9 million reduction in capital expenditures at BTD as work on BTD's Minnesota expansion project was winding down and nearing completion in the first quarter of 2016.

- A $2.1 million decrease in cash used for investments, reflecting the deposit of $2.0 million in proceeds from the sale of the assets of AEV, Inc. into an escrow account in the first quarter of 2015, with no similar transaction in the first quarter of 2016.

First quarter 2015 investing activities of discontinued operations includes $21.3 million in cash proceeds from the sale of the assets of AEV, Inc., partially offset by $1.8 million in cash used in investing activities of discontinued operations, mainly related to the purchase by AEV, Inc. of assets being leased under operating leases prior to the assets being sold.

Net cash provided by financing activities of continuing operations was $3.0 million for the three months ended March 31, 2016 compared with $28.5 million for the three months ended March 31, 2015. Financing activities in the first quarter of 2016 included $50 million in borrowings under a Term Loan Agreement and $3.4 million in proceeds from the issuance of stock under the automatic dividend reinvestment and share purchase plan, offset by $38.4 million in cash used to pay down short-term borrowings and checks written in excess of cash and $11.9 million in common stock dividend payments. The outstanding short-term borrowings that were paid down were, in part, used to fund the expansion of BTD's Minnesota facilities in 2015 and the September 1, 2015 acquisition of BTD-Georgia. Financing activities in the first quarter of 2015 included $37.8 million in short-term borrowings used, in part, to fund capital expenditures and $11.5 million in common stock dividend payments.

CAPITAL REQUIREMENTS

2016-2020 Capital Expenditures

The following table shows our 2015 capital expenditures and 2016 through 2020 anticipated capital expenditures and electric utility average rate base:

(in millions)	2015	2016	2017	2018	2019	2020
Capital Expenditures:						
Electric Segment:						
Transmission		$107	$96	$51	$5	$7
Renewables and Natural Gas Generation		4	3	162	113	81
Other		46	41	40	51	51
Total Electric Segment	$136	$157	$140	$253	$169	$139
Manufacturing and Plastics Segments	24	18	38	19	20	19

Total Capital Expenditures	$160	$175	$178	$272	$189	$158
Total Electric Utility Average Rate Base		$1,032	$1,087	$1,241	$1,295	$1,354

The capital expenditure plan for the 2016-2020 time period calls for $858 million based on the need for additional wind and solar in rate base and capital spending on a natural gas-fired plant that is expected to replace Hoot Lake Plant when it is retired in 2021. Taking into account the increased capital expenditure plan along with the impact of the recently extended bonus depreciation for income taxes, our compounded annual growth rate in rate base is expected to be 8.0%.

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2016 through 2020 timeframe.

Contractual Obligations

Our contractual obligations reported in the table on page 50 of our Annual Report on Form 10-K for the year ended December 31, 2015 increased $13.3 million in the first quarter of 2016. Our other purchase obligations increased $1.3 million in 2016, $11.9 million in 2017 and 2018 and $0.1 million in 2019, mainly as a result of additional purchase obligations entered into in the first quarter of 2016 related to the construction of the Big Stone South-Ellendale and Big Stone South-Brookings 345 kV transmission line MVPs.

CAPITAL RESOURCES

On May 11, 2015 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 11, 2018. On May 11, 2015, we entered into a Distribution Agreement with JPMS under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million through an At-the-Market offering program. We sold no shares under this program in the first quarter of 2016.

Short-Term Debt

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

(in thousands)	Line Limit	In Use on March 31, 2016	Restricted due to Outstanding Letters of Credit	Available on March 31, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 150,000	$ 20,880	$ —	$ 129,120	$ 90,334
OTP Credit Agreement	170,000	22,056	—	147,944	148,694
Total	$ 320,000	$ 42,936	$ —	$ 277,064	$ 239,028

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $150 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 29, 2015 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2019 to October 29, 2020. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 29, 2015 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2019 to October 29, 2020. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

Term Loan Agreement

On February 5, 2016 we entered into a Term Loan Agreement (the Term Loan Agreement) with the Banks named therein, JPMorgan Chase Bank, N.A. (JPMorgan), 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 we 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, we 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 our election of whether to make the advance a LIBOR advance. The Term Loan Agreement terminates on February 5, 2018.

On February 5, 2016 we 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 Term Loan Agreement contains a number of restrictions on us, Varistar and certain subsidiaries of Varistar, including restrictions on our and 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, as well as certain financial covenants as described below under the heading "Financial Covenants." 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 our credit ratings. Our obligations under the Term Loan Agreement are guaranteed by Varistar and certain of its subsidiaries.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the Purchasers named therein, pursuant to which OTP agreed to issue to the Purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). On February 27, 2014 OTP issued all $150 million aggregate principal amount of the Notes. OTP used a portion of the proceeds of the Notes to retire its $40.9 million term loan under a Credit Agreement with JPMorgan and to repay $82.5 million of short-term debt then outstanding under the OTP Credit Agreement. Remaining proceeds of the Notes were used to fund OTP construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of

the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

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

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (2011 Note Purchase Agreement). OTP also has outstanding its $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due

2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

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

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of March 31, 2016.

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

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

- Under the Otter Tail Corporation Credit Agreement and the Term Loan Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of March 31, 2016 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement and the Term Loan Agreement was 3.66 to 1.00.

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

- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of March 31, 2016 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.62 to 1.00.

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

As of March 31, 2016 our ratio of interest-bearing debt to total capitalization was 0.49 to 1.00 on a consolidated basis and 0.48 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $4.8 million, but our line of credit borrowing limits are not restricted by the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2016 BUSINESS OUTLOOK

We are reaffirming our consolidated diluted earnings per share guidance for 2016 to be in the range of $1.50 to $1.65. This guidance reflects the current mix of businesses we own, considers the cyclical nature of some of our businesses and reflects current economic challenges facing our Manufacturing and Plastics segments, as well as plans and strategies for improving future operating results. We expect capital expenditures for 2016 to be $175 million compared with $160 million in capital expenditures in 2015. Major projects in our planned expenditures for 2016 include investments in two large transmission line projects for the Electric segment, which are expected to positively impact earnings and provide an immediate return on capital.

Segment components of our 2016 earnings per share initial and revised guidance range compared with 2015 actual earnings are as follows:

	2015 EPS by Segment	2016 Guidance February 8, 2016		2016 Guidance Revised May 2, 2016	
Diluted Earnings Per Share		Low	High	Low	High
Electric	$ 1.29	$ 1.29	$ 1.32	$ 1.29	$ 1.32
Manufacturing	$ 0.11	$ 0.11	$ 0.15	$ 0.12	$ 0.16
Plastics	$ 0.32	$ 0.26	$ 0.30	$ 0.24	$ 0.28
Corporate	$ (0.16)	$ (0.16)	$ (0.12)	$ (0.15)	$ (0.11)
Total – Continuing Operations	$ 1.56	$ 1.50	$ 1.65	$ 1.50	$ 1.65
Expected Return on Equity		9.3 %	10.2 %	9.3 %	10.2 %

Contributing to our earnings guidance for 2016 are the following items:

- We expect 2016 Electric segment net income to be slightly higher than 2015 segment net income based on:
  - Normalized weather for the remainder of 2016.
  - Constructive outcome of a rate case filed in Minnesota in February 2016.
  - Rider recovery increases, including environmental riders in Minnesota, North Dakota and South Dakota related to the Big Stone AQCS environmental upgrades and transmission riders related to the Electric segments continuing investments in its share of the MVPs in South Dakota.

- Meeting forecasted sales to pipeline and commercial customers.

- A decrease in pension costs as a result of an increase in the discount rate from 4.35% to 4.76%.

offset by:

- The effect of the 2015 adoption of bonus depreciation for income taxes reducing projected earnings from Electric segment operations by $0.06 per share in 2016.

- Higher depreciation and property tax expense due to large capital projects being put into service.

- Higher short-term interest costs as major construction projects continue to be funded.

- Increased operating expenses associated with reagents and employee expenses.

- Increased transmission expenses associated with termination of historic integrated transmission agreements.

- We are raising our guidance for 2016 net income from our Manufacturing segment based on strong first quarter results, driven by improved productivity despite softening end markets, and continued focus on improved productivity and cost reductions for the remainder of the year. In spite of softening end markets, we expect 2016 net income from our Manufacturing segment to increase over 2015 due to:

- An increase at BTD due to increases in sales volume as a result of having BTD-Georgia in place for a full year. Full year sales for BTD-Georgia are now estimated to be $30 million compared with original expectations of $33 million. The decline is due to continued softness in end markets served by the BTD-Georgia location.

- Excluding the full year impact of BTD-Georgia, revenues are now expected to decline approximately 2%, compared with an original growth expectation of 7%. This change is due to challenging market conditions impacting end markets served by BTD. BTD has significant exposure to the agriculture, oil and gas and recreational vehicle end markets, all of which are forecasted to be down in 2016 compared to 2015.

- Improved margins on parts and tooling sales given improved productivity across all of BTD's locations as a result of lower expediting costs, costs of quality and maintenance expenses. These increases are expected to be offset by higher facility costs associated with BTD's expansion of its square footage.

- Scrap revenues, based on current commodity prices for scrap steel, are expected to be down in 2016 compared to 2015 given the excess capacity in the steel industry and the impact of low prices from imported steel.

- A decrease in earnings from T.O. Plastics mainly driven by an expected decrease in operating margins due to a shift in product mix relating to a customer bringing a product back into its own manufacturing facilities.

- Backlog for the manufacturing companies of approximately $102 million for 2016 compared with $106 million one year ago.

- We are lowering our guidance for 2016 net income for our Plastics segment as announced resin price increases in the second quarter are not expected to be fully passed on in sales prices due to current competitive pricing conditions. 2016 net income from this segment is expected to be down from 2015 with lower expected operating margins due to tighter spreads between raw material costs and sales prices, along with higher labor and freight costs.

- We expect lower corporate costs than originally estimated for 2016 due to continued cost reduction efforts.

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the board of directors. A discussion of critical accounting policies is included under the caption "Critical Accounting Policies Involving Significant Estimates" on pages 56 through 59 of our Annual Report on Form 10-K for the year ended

December 31, 2015. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2016.

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

In connection with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as "may", "will", "expect", "anticipate", "continue", "estimate", "project", "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act. These forward-looking statements involve risks and uncertainties. Actual results may differ materially from those contemplated by the forward-looking statements due to, among other factors, the risks and uncertainties described in the section entitled “Risk Factors” in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, as well as the various factors described below:

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

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

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

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

- We made a $10.0 million discretionary contribution to our defined benefit pension plan in January 2016. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

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

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

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

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

- Economic conditions could negatively impact our businesses.

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

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

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

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

- We are subject to risks associated with energy markets.

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

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

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

- OTP's operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

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

- Changes to regulation of generating plant emissions, including but not limited to carbon dioxide emissions, could affect our operating costs and the costs of supplying electricity to our customers.

- Competition from foreign and domestic manufacturers, the price and availability of raw materials, prices and supply of scrap or recyclable material and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

- Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for this segment.

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2016 we had exposure to market risk associated with interest rates because we had $50 million outstanding subject to a variable interest rate that is indexed to 30 day LIBOR plus 90 basis points under the Term Loan Agreement that terminates on February 5, 2018. We had $20.9 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.75% under our $150 million revolving credit facility, and OTP had $22.1 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under its $170 million revolving credit facility.

All of our remaining consolidated long-term debt outstanding on March 31, 2016 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

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

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

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

Item 4. Controls and Procedures

Under the supervision and with the participation of company management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of March 31, 2016, the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2016.

During the fiscal quarter ended March 31, 2016, there were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, “Risk Factors” on pages 26 through 32 of our Annual Report on Form 10-K for the year ended December 31, 2015.

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

We do not have a publicly announced stock repurchase program. The following table shows common shares of the Company that were surrendered to us by employees to pay taxes in connection with shares issued for incentive awards in February 2016 under our 2014 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
January 2016	—	—
February 2016	1,868	$ 28.40
March 2016	—	—
Total	1,868	

Item 6. Exhibits

4.1 Term Loan Agreement dated as of February 5, 2016, between Otter Tail Corporation and the Banks named therein, and JPMorgan Chase Bank, N.A., as administrative agent for the Banks, and J.P. Morgan Securities LLC, as Lead Arranger and Book Runner.

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

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

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

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

101 Financial statements from the Quarterly Report on Form 10-Q of Otter Tail Corporation for the quarter ended March 31, 2016, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows and (v) the Condensed Notes to Consolidated Financial Statements.

SIGNATURES

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

OTTER TAIL CORPORATION

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

Dated: May 9, 2016

EXHIBIT INDEX

Exhibit Number	Description
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