Otter Tail Corp
Form 10-Q
November 07, 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 September 30, 2016

OR

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

For the transition period from to

Commission file number 0-53713

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

Minnesota	27-0383995
(State or other jurisdiction of 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:

October 31, 2016 – 39,268,205 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)	September 30, 2016	December 31, 2015
Assets		
Current Assets		
Cash and Cash Equivalents	$—	$ —
Accounts Receivable:		
Trade—Net	69,556	62,974
Other	7,082	9,073
Inventories	80,848	85,416
Unbilled Revenues	14,882	17,869
Income Taxes Receivable	—	4,000
Regulatory Assets	19,958	18,904
Other	11,139	8,453
Assets of Discontinued Operations	249	—
Total Current Assets	203,714	206,689
Investments	8,065	8,284
Other Assets	33,707	32,784
Goodwill	37,572	39,732
Other Intangibles—Net	15,291	15,673
Regulatory Assets	118,123	127,707
Plant		
Electric Plant in Service	1,842,931	1,820,763
Nonelectric Operations	215,074	201,343
Construction Work in Progress	143,999	79,612
Total Gross Plant	2,202,004	2,101,718
Less Accumulated Depreciation and Amortization	749,569	713,904

Net Plant	1,452,435	1,387,814
Total Assets	$1,868,907	$ 1,818,683

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation

Consolidated Balance Sheets

(not audited)

(in thousands, except share data)	September 30, 2016	December 31, 2015
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	$ 37,173	$ 80,672
Current Maturities of Long-Term Debt	85,490	52,422
Accounts Payable	77,704	89,499
Accrued Salaries and Wages	15,573	16,182
Accrued Taxes	12,635	14,827
Other Accrued Liabilities	16,050	15,416
Liabilities of Discontinued Operations	1,631	2,098
Total Current Liabilities	246,256	271,116
Pensions Benefit Liability	95,653	104,912
Other Postretirement Benefits Liability	49,718	48,730
Other Noncurrent Liabilities	25,857	23,854
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	222,244	207,669
Deferred Tax Credits	23,264	24,506
Regulatory Liabilities	79,835	77,432
Other	8,604	11,595
Total Deferred Credits	333,947	321,202
Capitalization		
Long-Term Debt—Net	460,757	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—39,224,553 Shares; 2015—37,857,186 Shares	196,123	189,286

Premium on Common Shares	329,288	293,610
Retained Earnings	134,884	126,025
Accumulated Other Comprehensive Loss	(3,576)	(3,898)
Total Common Equity	656,719	605,023
Total Capitalization	1,117,476	1,048,869
Total Liabilities and Equity	$ 1,868,907	$ 1,818,683

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Income

(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating Revenues				
Electric	$102,712	$100,538	$313,615	$304,998
Product Sales	94,463	99,485	293,284	286,019
Total Operating Revenues	197,175	200,023	606,899	591,017
Operating Expenses				
Production Fuel - Electric	14,789	11,124	40,479	29,906
Purchased Power - Electric System Use	11,473	18,725	43,486	62,101
Electric Operation and Maintenance Expenses	36,207	32,648	115,206	107,929
Cost of Products Sold (depreciation included below)	75,405	78,428	228,993	224,912
Other Nonelectric Expenses	10,197	10,771	30,890	32,057
Depreciation and Amortization	18,314	15,141	55,128	44,337
Property Taxes - Electric	3,506	3,560	10,774	10,324
Total Operating Expenses	169,891	170,397	524,956	511,566
Operating Income	27,284	29,626	81,943	79,451
Interest Charges	8,026	7,730	23,996	23,175
Other Income	499	334	2,431	1,473
Income Before Income Taxes—Continuing Operations	19,757	22,230	60,378	57,749
Income Tax Expense—Continuing Operations	5,163	6,521	15,738	14,602
Net Income from Continuing Operations	14,594	15,709	44,640	43,147
Discontinued Operations				
Income (Loss) - net of Income Tax Expense (Benefit) of $14, ($168), $114 and ($2,873) for the respective periods	22	(252)	171	(4,316)
Impairment Loss - net of Income Tax Benefit of $0 for the nine months ended September 30, 2015	—	—	—	(1,000)
(Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of ($43) and $4,493 for the three and nine months ended September 30, 2015	—	(65)	—	6,932
Net Income (Loss) from Discontinued Operations	22	(317)	171	1,616
Net Income	14,616	15,392	44,811	44,763
Average Number of Common Shares Outstanding—Basic	38,832,659	37,575,413	38,316,324	37,417,283
Average Number of Common Shares Outstanding—Diluted	39,005,706	37,794,543	38,457,401	37,636,413
Basic Earnings (Loss) Per Common Share:				
Continuing Operations	$0.38	$0.42	$1.17	$1.15
Discontinued Operations	—	(0.01)	—	0.05

	$0.38	$0.41	$1.17	$1.20
Diluted Earnings (Loss) Per Common Share:				
Continuing Operations	$0.37	$0.42	$1.16	$1.15
Discontinued Operations	—	(0.01)	0.01	0.04
	$0.37	$0.41	$1.17	$1.19
Dividends Declared Per Common Share	$0.3125	$0.3075	$0.9375	$0.9225

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation

Consolidated Statements of Comprehensive Income

(not audited)

(in thousands)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Net Income	$ 14,616	$ 15,392	$ 44,811	$ 44,763
Other Comprehensive Income:				
Unrealized Gain on Available-for-Sale Securities:				
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(3)	—	(3)	(3)
(Losses) Gains Arising During Period	(35)	6	65	1
Income Tax Benefit (Expense)	13	(2)	(22)	1
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(25)	4	40	(1)
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	161	205	470	616
Income Tax Expense	(64)	(82)	(188)	(247)
Pension and Postretirement Benefit Plans – net-of-tax	97	123	282	369
Total Other Comprehensive Income	72	127	322	368
Total Comprehensive Income	$ 14,688	$ 15,519	$ 45,133	$ 45,131

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation

Consolidated Statements of Cash Flows

(not audited)

(in thousands)	Nine Months Ended September 30, 2016	2015
Cash Flows from Operating Activities		
Net Income	$44,811	$44,763
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Gain from Sale of Discontinued Operations	—	(6,932)
Net (Income) Loss from Discontinued Operations	(171)	5,316
Depreciation and Amortization	55,128	44,337
Deferred Tax Credits	(1,242)	(1,408)
Deferred Income Taxes	14,924	12,244
Change in Deferred Debits and Other Assets	5,595	13,839
Discretionary Contribution to Pension Plan	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	5,999	4,345
Allowance for Equity/Other Funds Used During Construction	(605)	(944)
Change in Derivatives Net of Regulatory Deferral	—	(28)
Stock Compensation Expense—Equity Awards	1,151	1,428
Other—Net	(73)	(27)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(3,490)	(14,020)
Change in Inventories	4,766	5,721
Change in Other Current Assets	1,690	2,163
Change in Payables and Other Current Liabilities	(5,945)	(17,490)
Change in Interest and Income Taxes Receivable/Payable	2,538	(1,499)
Net Cash Provided by Continuing Operations	115,076	81,808
Net Cash Used for Discontinued Operations	(333)	(11,581)
Net Cash Provided by Operating Activities	114,743	70,227
Cash Flows from Investing Activities		
Capital Expenditures	(125,913)	(115,321)
Net Proceeds from Disposal of Noncurrent Assets	4,167	2,956
Purchase Price Adjustment (Payment) – BTD-Georgia Acquisition	1,500	(30,806)
Cash Used for Investments and Other Assets	(3,161)	(7,297)
Net Cash Used in Investing Activities - Continuing Operations	(123,407)	(150,468)
Net Proceeds from Sale of Discontinued Operations	—	32,765
Net Cash Used in Investing Activities - Discontinued Operations	—	(1,769)
Net Cash Used in Investing Activities	(123,407)	(119,472)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(841)	(1,236)
Net Short-Term Debt (Repayments) Borrowings	(43,499)	76,098

Proceeds from Issuance of Common Stock – net of Issuance Expenses	39,378	10,979
Payments for Retirement of Capital Stock	(104)	(1,596)
Proceeds from Issuance of Long-Term Debt	50,000	—
Short-Term and Long-Term Debt Issuance Expenses	(157)	(7)
Payments for Retirement of Long-Term Debt	(161)	(149)
Dividends Paid and Other Distributions	(35,952)	(34,607)
Net Cash Provided by Financing Activities – Continuing Operations	8,664	49,482
Net Cash Provided by Financing Activities – Discontinued Operations	—	321
Net Cash Provided by Financing Activities	8,664	49,803
Net Change in Cash and Cash Equivalents - Discontinued Operations	—	(10)
Net Change in Cash and Cash Equivalents	—	548
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$—	$548

See accompanying condensed notes to consolidated financial statements.

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OTTER TAIL CORPORATION

<u>CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS</u>
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed notes thereto should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015. Because of seasonal and other factors, the earnings for the three- and nine-month periods ended September 30, 2016 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following condensed notes are numbered to correspond to numbers of the notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

1. Summary of Significant Accounting Policies

<u>Revenue Recognition</u>

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, the price is fixed or determinable and collectability is reasonably assured. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as Otter Tail Power Company's (OTP) 2015 forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 815, *Derivatives and Hedging*. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

Agreements Subject to Legally Enforceable Netting Arrangements

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

Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a 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 September 30, 2016 and December 31, 2015:

September 30, 2016 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		$4,408	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		3,506	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	$ 764		
Total Assets	$ 764	$7,914	
Liabilities:			
Other Accrued Liabilities:			
Derivative Liabilities – Forward Gasoline Purchase Contracts		$49	
Total Liabilities		$49	

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)	September 30, 2016	December 31, 2015
Finished Goods	$ 21,888	$ 25,971
Work in Process	13,774	12,821
Raw Material, Fuel and Supplies	45,186	46,624
Total Inventories	$ 80,848	$ 85,416

Goodwill and Other Intangible Assets

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

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

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

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

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

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

September 30, 2016 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods

Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 7,577	$ 14,914	39-227 months
Covenant not to Compete	590	213	377	23 months
Total	$ 23,081	$ 7,790	$ 15,291	
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 September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Amortization Expense – Intangible Assets	$ 348	$ 282	$ 1,103	$ 770

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

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

Supplemental Disclosures of Cash Flow Information

	As of September 30,	
(in thousands)	2016	2015
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$ 11,552	$ 21,760

Coyote Station Lignite Supply Agreement – Variable Interest Entity—In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is not required to include CCMC in its consolidated financial statements.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commenced with the initial delivery of coal to Coyote Station in May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. Coyote Station started taking delivery of coal and paying for coal and the accumulated development fees and capital charges under the LSA in May 2016. OTP's 35% share of the unrecovered development period costs, development fees and capital charges incurred by CCMC through September 30, 2016 is $61.7 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 September 30, 2016 could be as high as $61.7 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. As of September 30, 2016 the Company has reviewed its revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and is evaluating transition options. The Company does not plan to adopt the updated guidance prior to January 1, 2018.

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

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

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

ASU 2016-02—In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous leases guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company is currently reviewing ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and evaluating transition options. The Company does not currently plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

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

2. Business Combinations and Segment Information

Business Combinations

On September 1, 2015 BTD-Illinois, a wholly owned subsidiary of BTD, acquired the assets of Impulse of Dawsonville, Georgia for $30.8 million in cash. A post-closing reduction in the purchase price of $1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of $29.3 million. The acquired business, operating under the name BTD-Georgia, is a full-service metal fabricator located 30 miles north of Atlanta, Georgia, which offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers. In addition to serving some of BTD's existing customers from a location closer to the customers' manufacturing facilities, this acquisition provides opportunities for growth in new and existing markets for BTD with complementing production capabilities that 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 disclosing the final allocation of the purchase price assigned to each major asset and liability category of BTD-Georgia:

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

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

Segment Information

The Company's businesses have been classified into three segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision makers. These businesses sell products and provide services to customers primarily in the United States. The three segments are: Electric, Manufacturing and Plastics.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.

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

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single customer accounted for over 10% of the Company's consolidated revenues in 2015. All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.5% and 98.2% of its operating revenues for the respective three-month periods ended September 30, 2016 and 2015, and 98.6% and 97.2% of its operating revenues for the respective nine-month periods ended September 30, 2016 and 2015.

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

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Electric	$102,723	$100,567	$313,642	$305,078
Manufacturing	52,171	52,460	170,443	160,492
Plastics	42,292	47,025	122,841	125,531
Intersegment Eliminations	(11)	(29)	(27)	(84)
Total	$197,175	$200,023	$606,899	$591,017

Interest Charges

(in thousands)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Electric	$ 6,304	$ 6,069	$ 18,744	$ 18,273
Manufacturing	974	900	2,972	2,578
Plastics	273	257	796	782
Corporate and Intersegment Eliminations	475	504	1,484	1,542
Total	$ 8,026	$ 7,730	$ 23,996	$ 23,175

Income Tax Expense—Continuing Operations

(in thousands)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Electric	$ 4,730	$ 4,761	$ 11,262	$ 9,995
Manufacturing	182	855	2,992	2,516
Plastics	1,577	2,206	5,206	6,159
Corporate	(1,326)	(1,301)	(3,722)	(4,068)
Total	$ 5,163	$ 6,521	$ 15,738	$ 14,602

Net Income (Loss)

(in thousands)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Electric	$ 12,513	$ 12,921	$ 34,199	$ 34,351
Manufacturing	1,246	1,714	6,108	4,810
Plastics	2,346	3,534	7,983	9,919
Corporate	(1,511)	(2,460)	(3,650)	(5,933)
Discontinued Operations	22	(317)	171	1,616
Total	$ 14,616	$ 15,392	$ 44,811	$ 44,763

Identifiable Assets

(in thousands)	September 30, 2016	December 31, 2015
Electric	$ 1,575,790	$ 1,520,887
Manufacturing	168,705	173,860
Plastics	86,731	81,624
Corporate	37,432	42,312
Discontinued Operations	249	—
Total	$ 1,868,907	$ 1,818,683

3. Rate and Regulatory Matters

Below are descriptions of OTP’s major capital expenditure projects that have had, or will have, a significant impact on OTP’s revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the Federal Energy Regulatory Commission (FERC), impacting OTP’s revenues in 2016 and 2015.

Major Capital Expenditure Projects

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP’s capitalized cost of the project, excluding Allowance for Funds Used During Construction (AFUDC), as of September 30, 2016 was approximately $199.3 million.

Fargo–Monticello 345 kiloVolt (kV) Capacity Expansion 2020 (CapX2020) Project (the Fargo Project)—OTP has invested approximately $81.5 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 $26.3 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO approved the Brookings Project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation of MVPs is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. The final segments of this line were energized on March 26, 2015.

The Big Stone South–Brookings MVP and CapX2020 Project—This 345 kV transmission line, currently under construction, will extend approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – MN, a subsidiary of Xcel Energy Inc., jointly developed this project with obligations to have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line is expected to be in service in fall 2017. OTP's capitalized cost of this project as of September 30, 2016 was approximately $56.4 million, which includes assets that are 100% owned by OTP.

The Big Stone South–Ellendale MVP—This 345 kV transmission line will extend 160 to 170 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU) with obligations of having equal ownership interest in the transmission line portion of the project. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized cost of this project as of September 30, 2016 was approximately $39.8 million, which includes assets that are 100% owned by OTP.

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

Minnesota

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

($ in thousands)	Annualized or Test Year	Actual Through September 30, 2016 Three Months Ended	Nine Months Ended
Revenue Increase Requested	$ 19,296		
Increase Percentage Requested	9.80 %		
Jurisdictional Rate Base	$ 483,000		
Interim Revenue Increase (subject to refund)	$ 16,816	$ 3,818	$ 6,875

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

Revenue Requirement Deficiency Cost Factors *(in thousands)*	2016 Test Year Allocation
Increased Rate Base	$ 10,000
Increased Expenses	7,700

Other		1,596
Total Requested Revenue Increase	$	19,296
Excluded from Interim Rates: Rate Base Effect of Prepaid Pension Asset		(2,480)
Approved Interim Revenue Increase (subject to refund)	$	16,816

The deadline for submission of intervenor direct testimony was August 16, 2016. Direct testimony of the MNDOC included a recommendation for an 8.86% allowed rate of return on equity and direct testimony of the Minnesota Office of the Attorney General (OAG) included a recommendation for a 6.96% allowed rate of return on equity. In response, in rebuttal testimony, OTP modified its request to provide for an allowed rate of return on equity of 10.05%. In rebuttal testimony, the MNDOC revised its recommendation to an 8.66% allowed rate of return on equity, and the Minnesota OAG revised its recommendation to a 7.14% allowed rate of return on equity. The deadline for submission of surrebuttal testimony was September 28, 2016. Hearings before the Administrative Law Judge (ALJ) occurred on October 13, 14 and 17, 2016.

Based on OTP's modifications to its original request and other expected outcomes in the aforementioned rate case, OTP has recorded an estimated interim rate refund of $2.3 million as of September 30, 2016.

Expected dates for next steps in the procedural schedule:

·	Report of ALJ	January 5, 2017
·	Final order	March 16, 2017

<u>2010 General Rate Case</u>—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%.

<u>Minnesota Conservation Improvement Programs (MNCIP)</u>—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 a 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a $4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

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

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

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

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

North Dakota

General Rates—OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) rider which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed along with a return on investment. On March 25, 2015 the NDPSC approved OTP's 2014 annual update to the NDRRA rider, including a change in rate design from an amount per kilowatt-hour consumed to a percentage of a customer's bill, with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of Federal

Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the return on equity (ROE) component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case. The NDPSC approved OTP's 2014 annual update to its TCR rider rate on December 17, 2014 with an effective date of January 1, 2015. On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately $10.2 million for 2016 compared with $8.5 million for 2015, including costs assessed by the MISO as well as new costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These new costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016. On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, which includes a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of the decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the current true-up over-collection balance be spread over the next two years for purposes of reducing the volatility of the rates from year to year. An informal hearing is scheduled for November 30, 2016.

Environmental Cost Recovery Rider—On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP's North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. On December 18, 2013 the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. The ECR provides for a current return on CWIP and a return on investment at the level approved in OTP's most recent general rate case. The NDPSC approved OTP's 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant Mercury and Air Toxics Standards (MATS) project costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from $12.2 million to $10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

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

South Dakota

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

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover OTP's South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately $2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.3 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. This year's lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS.

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Rate Rider *(in thousands)*	2016	2015	2016	2015
Minnesota				
Conservation Improvement Program Costs and Incentives[1]	$ 2,839	$ 1,970	$ 7,554	$ 5,508
Transmission Cost Recovery	779	1,141	4,188	3,968
Environmental Cost Recovery	3,127	2,565	9,362	7,722
North Dakota				
Renewable Resource Adjustment	2,170	2,073	6,151	5,898
Transmission Cost Recovery	1,950	1,565	6,155	4,912
Environmental Cost Recovery	2,762	2,312	8,344	7,233
South Dakota				
Transmission Cost Recovery	335	267	1,397	911
Environmental Cost Recovery	691	461	1,951	1,484
Conservation Improvement Program Costs and Incentives	135	234	418	464

[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 ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the 12.38% ROE used in MISO’s transmission rates over a 15-month period ending in February 2015 to a proposed 9.15%. On October 16, 2014 the FERC issued an order finding that the current MISO ROE may be unjust and unreasonable and setting the issue for hearing. A non-binding decision by the presiding ALJ was issued on December 22, 2015 finding that the MISO transmission owners’ ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. 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 issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP’s incentive rate filing, OTP’s ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

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

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded a reduction in revenue of $0.1 million in the three-month period ended September 30, 2015, and $1.3 million and $0.9 million in the nine-month periods ended September 30, 2016 and 2015, respectively, and has a $2.4 million liability on its balance sheet as of September 30, 2016, representing OTP's best estimate of a refund obligation that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. As a result of the FERC order issued on September 28, 2016 in the first complaint proceeding establishing an allowed ROE of 10.32%, no additional liability was recorded in the third quarter of 2016.

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:

	September 30, 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	$ 94,671	$102,110	see below
Deferred Marked-to-Market Losses[1]	4,063	7,483	11,546	51 months
Conservation Improvement Program Costs and Incentives[2]	4,286	3,079	7,365	24 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	—	6,031	6,031	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	619	2,444	3,063	55 months
North Dakota Renewable Resource Rider Accrued Revenues[2]	1,608	826	2,434	18 months
Debt Reacquisition Premiums[1]	349	1,278	1,627	192 months
Deferred Income Taxes[1]	—	1,157	1,157	asset lives
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	748	—	748	12 months
Big Stone II Unrecovered Project Costs – South Dakota[2]	101	567	668	80 months
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	—	544	544	27 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	474	43	517	27 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	225	—	225	12 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	46	—	46	12 months
Total Regulatory Assets	$19,958	$ 118,123	$138,081	

Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$—	$ 77,603	77,603	asset lives
Refundable Fuel Clause Adjustment Revenues	2,301	—	2,301	12 months
North Dakota Transmission Cost Recovery Rider Accrued Refund	638	758	1,396	24 months
Minnesota Transmission Cost Recovery Rider Accrued Refund	1,356	—	1,356	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	712	385	1,097	19 months
Deferred Income Taxes	—	918	918	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	370	—	370	12 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	296	—	296	12 months
North Dakota Environmental Cost Recovery Rider Accrued Refund	256	—	256	12 months
Other	5	91	96	207 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	—	80	80	27 months
Total Regulatory Liabilities	$5,934	$ 79,835	$85,769	
Net Regulatory Asset Position	$14,024	$ 38,288	$52,312	

[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.*

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(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[1]	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 September 30, 2016 relate to forward purchases of energy scheduled for delivery through December 2020.

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

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

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

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 192 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*.

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

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.

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

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

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 September 30, 2016.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers. On April 4, 2013 the MPUC approved OTP's request to set the rider rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered over an 18-month period beginning with the establishment of interim rates in April 2016.

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

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 September 30, 2016.

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

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The 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 September 30, 2016.

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

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

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Open Contract Positions Subject to Legally Enforceable Netting Arrangements

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

(in thousands)	September 30, 2016	December 31, 2015
Open Contract Gain Positions Subject to Legally Enforceable Netting Arrangements	$ —	$ —
Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements	(15,220)	(16,070)
Net Balance Subject to Legally Enforceable Netting Arrangements	$ (15,220)	$ (16,070)

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

Loss Position *(in thousands)*	September 30, 2016	December 31, 2015
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 49	$ 199
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	15,171	15,871
Loss Contracts with No Ratings Triggers or Deposit Requirements	—	—
Loss Position	$ 15,220	$ 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	$ 15,171	$ 15,871
Offsetting Gains with Counterparties under Master Netting Agreements	—	—
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 15,171	$ 15,871

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

<u>Reconciliation of Common Shareholders' Equity</u>

(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	6,855	34,601			41,456
Common Stock Retirements	(18)	(86)			(104)
Net Income			44,811		44,811
Other Comprehensive Income				322	322
Employee Stock Incentive Plans Expense		1,163			1,163
Common Dividends ($0.9375 per share)			(35,952)		(35,952)
Balance, September 30, 2016	$ 196,123	$ 329,288	$ 134,884	$ (3,576)	$ 656,719

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 September 30, 2016:

Common Shares Outstanding, December 31, 2015	37,857,186
Issuances:	
At-the-Market Offering	977,712
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	131,111
Cash Invested	79,494
Executive Stock Performance Awards (2013 and 2014 shares earned)	54,700
Employee Stock Purchase Plan:	
Cash Invested	40,324
Dividends Reinvested	19,090
Employee Stock Ownership Plan	23,837
Restricted Stock Issued to Directors	23,200
Vesting of Restricted Stock Units	21,025
Directors Deferred Compensation	542
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(3,668)
Common Shares Outstanding, September 30, 2016	39,224,553

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three- and nine-month periods ended September 30, 2016 and 2015. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company’s directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation:

	Three Months ended September 30		Nine Months ended September 30	
	2016	2015	2016	2015
Weighted Average Common Shares Outstanding – Basic	38,832,659	37,575,413	38,316,324	37,417,283
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	103,084	141,540	80,450	141,540

Period-to-Date Performance				
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	48,645	44,280	42,620	44,280
Nonvested Restricted Shares	18,029	31,079	14,556	31,079
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	3,289	2,231	3,451	2,231
Total Dilutive Shares	173,047	219,130	141,077	219,130
Weighted Average Common Shares Outstanding – Diluted	39,005,706	37,794,543	38,457,401	37,636,413

The effect of dilutive shares on earnings per share for the three- and nine-month periods ended September 30, 2016 and 2015, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in either period.

7. Share-Based Payments

Stock Incentive Awards

In 2016 the following stock incentive awards were granted to the Company's employees and nonemployee directors under the 2014 Stock Incentive Plan:

Award	Shares/ Units Granted	Grant-Date Fair Value per Award	Vesting
February 4, 2016:			
Stock Performance Awards Granted to Executive Officers	81,500	$ 24.03	December 31, 2018
Restricted Stock Units Granted to Executive Officers	22,000	$ 28.915	25% per year through February 6, 2020
April 11, 2016:			
Restricted Stock Granted to Nonemployee Directors	23,200	$ 28.66	25% per year through April 8, 2020
Restricted Stock Units Granted to Key Employees	15,800	$ 24.00	100% on April 8, 2020
September 21, 2016:			
Restricted Stock Units Granted to Key Employee	1,420	$ 30.59	100% on April 8, 2020

Under the 2016 performance share award agreements, the aggregate award for performance at target is 81,500 shares. For target performance the Company's executive officers would earn an aggregate of 54,333 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2016 through December 31, 2018, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2016 and the average closing price for the 20 trading days immediately preceding January 1, 2019, respectively. The Company's executive officers would also earn an aggregate of 27,167 common shares for achieving the target set for the Company's 3-year average adjusted ROE. 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).

Vesting of restricted stock and 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 granted to an executive officer was the average of the high and low market price per share on the date of grant. The restricted shares granted to the Company’s nonemployee directors are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreements. The grant-date fair value of each restricted share was based on the market value of one share of the Company’s common stock on the date of grant. The grant-date fair value of each restricted stock unit granted to a key employee that is not an executive officer of the Company was based on the market value of one share of the Company’s common stock on the date of grant, discounted for the value of the dividend exclusion on those restricted stock units over the four-year vesting period.

The 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 September 30, 2016 the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $5.1 million (before income taxes) which will be amortized over a weighted-average period of 2.4 years.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Stock Performance Awards Granted to Executive Officers	$ 455	$ (142)	$ 1,296	$ 915
Restricted Stock Units Granted to Executive Officers	64	36	373	416
Restricted Stock Granted to Executive Officers	22	29	73	330
Restricted Stock Granted to Directors	128	107	363	311
Restricted Stock Units Granted to Nonexecutive Employees	62	86	207	233
Employee Stock Purchase Plan (15% discount)	47	44	135	138
Totals	$ 778	$ 160	$ 2,447	$ 2,343

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, there are limitations on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP debt agreements contain restrictions on the payment of cash dividends on a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of September 30, 2016 the Company was in compliance with these financial covenants. See note 10 to the Company's consolidated financial statements on Form 10-K for the year ended December 31, 2015 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 47.5% and 58.1% based on OTP's 2016 capital structure petition approved by order of the MPUC on August 2, 2016. OTP's equity to total capitalization ratio including short-term debt was

52.9% as of September 30, 2016. Total capitalization for OTP cannot currently exceed $1,123,168,000.

9. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2015 OTP had commitments under contracts, including its share of construction program commitments extending into 2019, of approximately $89.6 million. At September 30, 2016 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately $137.4 million.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2040. In 2016, OTP entered into a $3.5 million electric generating capacity purchase agreement for the period June 2017 through May 2019.

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

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. On September 27, 2016 OTP entered into an agreement to lease rail cars for the delivery of coal to Big Stone Plant through October of 2026 with OTP's share of the lease payments totaling $970,000 over the term of the lease. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment.

Contingencies

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

OTP was a party to proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005. As many as 200 utilities, generators and power marketers participated in the proceedings, which concluded on May 2, 2016. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with FERC to market participants, revisions to the RSG rate based on several FERC orders and FERC's decision to resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the United States Court of Appeals for the District of Columbia (D.C. Circuit). The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is both a petitioner and an intervenor in these cases. The scope of the issues that will be subject to appeal at the D.C. Circuit have not yet been finalized. In addition, MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders. Although the Company cannot estimate OTP's exposure at this time, a final order reversing the relevant FERC orders could have a material adverse effect on the Company's results of operations.

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, excluding any liability for RSG charges for which an estimate cannot be made at this time.

In 2014, the Environmental Protection Agency (EPA) published proposed standards of performance for CO2 emissions from new fossil fuel-fired power plants, proposed CO2 emission guidelines for existing fossil fuel-fired power plants and proposed CO2 standards of performance for CO2 emissions from reconstructed and modified fossil fuel-fired power plants under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. All of these rules have been challenged on legal grounds and are currently pending before the D.C. Circuit. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO2 emission guidelines for existing fossil fuel-fired power plants, pending disposition of petitions for review in the D.C. Circuit and, if a petition for a writ of certiorari seeking review by the U.S. Supreme Court were granted, any final Supreme Court determination. The D.C. Circuit heard oral argument on challenges to the CO2 emission guidelines on September 27, 2016 before the full court, and a decision may be rendered in late 2016 or early 2017. Given the pending litigation, 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 other matters pending as of September 30, 2016 will not be material.

10. Short-Term and Long-Term Borrowings

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

(in thousands)	Line Limit	In Use on September 30, 2016	Restricted due to Outstanding Letters of Credit	Available on September 30, 2016	Available on December 31, 2015
Otter Tail Corporation Credit Agreement	$ 150,000	$ —	$ —	$ 150 000	$ 90,334
OTP Credit Agreement	170,000	37,173	50	132,777	148,694
Total	$ 320,000	$ 37,173	$ 50	$ 282,777	$ 239,028

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On October 31, 2016 both the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were amended to extend the expiration dates by one year from October 29, 2020 to October 29, 2021. Also, the line limit on the Otter Tail Corporation Credit Agreement was reduced from $150 million to $130 million.

Debt Issuances and Retirements

2016 Note Purchase Agreement—On September 23, 2016 the Company entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which the Company has agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of the Company’s 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The Company’s obligations under the 2016 Note Purchase Agreement and the 2026 Notes will be guaranteed by the Company’s Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The 2026 Notes are expected to be issued on December 13, 2016, subject to the satisfaction of certain customary conditions to closing.

The Company may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by the Company of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. The Company is required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if the Company and its Material Subsidiaries sell a “substantial part” of their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in accordance with the terms of the 2016 Note Purchase Agreement, the Company is required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and the Material Subsidiaries that became effective on execution of the 2016 Note Purchase Agreement. These include restrictions on the Company’s and the Material Subsidiaries’ abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on the Company’s and the Material Subsidiaries’ shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants. Specifically, the Company may not permit the ratio of its Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) to Total Capitalization (as defined in the 2016 Note Purchase Agreement) to be greater than 0.60 to 1.00, determined as of the end of each fiscal quarter, and may not permit the Interest and Dividend Coverage Ratio (as defined in the 2016 Note Purchase Agreement) to be less than 1.50 to 1.00 for any period of four consecutive fiscal quarters. The Company is also restricted from allowing its Priority Debt (as defined in the 2016 Note Purchase Agreement) to exceed 10% of Total Capitalization, determined as of the end of each fiscal quarter. The

2016 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 the Company's or the Material Subsidiaries' credit ratings.

The Company intends to use the proceeds of the 2026 Notes to repay existing debt, including the remaining $52,330,000 of its 9.000% Senior Notes due December 15, 2016, and for general corporate purposes.

$50 Million Term Loan Agreement—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 September 30, 2016 and December 31, 2015:

September 30, 2016 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$37,173	$ —	$ 37,173
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		126	126
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021		873	873
Total	$445,000	$ 103,329	$ 548,329
Less: Current Maturities net of Unamortized Debt Issuance Costs	32,958	52,532	85,490
Unamortized Long-Term Debt Issuance Costs	1,920	162	2,082
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$410,122	$ 50,635	$ 460,757
Total Short-Term and Long-Term Debt (with current maturities)	$480,253	$ 103,167	$ 583,420

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

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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 September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Service Cost—Benefit Earned During the Period	$ 1,376	$ 1,514	$ 4,139	$ 4,544
Interest Cost on Projected Benefit Obligation	3,603	3,336	10,646	10,008
Expected Return on Assets	(4,857)	(4,595)	(14,590)	(13,787)
Amortization of Prior-Service Cost:				
From Regulatory Asset	48	47	142	141
From Other Comprehensive Income[1]	1	2	3	4
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,411	1,669	3,865	5,007
From Other Comprehensive Income[1]	32	42	95	128
Net Periodic Pension Cost	$ 1,614	$ 2,015	$ 4,300	$ 6,045

[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 September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Service Cost—Benefit Earned During the Period	$ 63	$ 48	$ 189	$ 142
Interest Cost on Projected Benefit Obligation	417	380	1,251	1,142
Amortization of Prior-Service Cost:				

From Regulatory Asset	4	5	12	13
From Other Comprehensive Income[1]	9	9	28	28
Amortization of Net Actuarial Loss:				
From Regulatory Asset	74	83	220	250
From Other Comprehensive Income[2]	111	151	334	452
Net Periodic Pension Cost	$ 678	$ 676	$ 2,034	$ 2,027
[1]Amortization of Prior Service Costs from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	$ 3	$ 3	$ 11	$ 11
Other Nonelectric Expenses	6	6	17	17
[2]Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	$ 68	$ 78	$ 204	$ 233
Other Nonelectric Expenses	43	73	130	219

<u>Postretirement Benefits</u>—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 September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Service Cost—Benefit Earned During the Period	$ 365	$ 324	$ 976	$ 972
Interest Cost on Projected Benefit Obligation	794	524	1,877	1,573
Amortization of Prior-Service Cost:				
From Regulatory Asset	34	52	100	154
From Other Comprehensive Income[1]	1	1	3	4
Amortization of Net Actuarial Loss:				
From Regulatory Asset	284	—	284	—
From Other Comprehensive Income[1]	7	—	7	—
Net Periodic Postretirement Benefit Cost	$ 1,485	$ 901	$ 3,247	$ 2,703
Effect of Medicare Part D Subsidy	$ (177)	$ (372)	$ (692)	$ (1,115)

[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 September 30, 2016 and December 31, 2015 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.75% and LIBOR plus 1.25%, respectively, which approximate market rates.

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

	September 30, 2016		December 31, 2015	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Short-Term Debt	(37,173)	(37,173)	(80,672)	(80,672)
Long-Term Debt including Current Maturities	(546,247)	(618,875)	(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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2016	2015	2016	2015
Income Before Income Taxes – Continuing Operations	$ 19,757	$ 22,230	$ 60,378	$ 57,749
	7,705	8,670	23,547	22,522

Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%)				
Increases (Decreases) in Tax from:				
Federal Production Tax Credits	(1,423)	(1,437)	(4,994)	(5,147)
R&D Tax Credits	(223)	2	(445)	(7)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212)	(212)	(637)	(637)
Employee Stock Ownership Plan Dividend Deduction	(157)	(171)	(472)	(514)
Corporate Owned Life Insurance	(92)	185	(664)	(39)
Investment Tax Credits	(87)	(143)	(262)	(428)
Adjustment for Uncertain Tax Positions	(57)	281	(31)	367
AFUDC Equity	(51)	(144)	(238)	(369)
Section 199 Domestic Production Activities Deduction	(9)	(362)	(207)	(1,087)
Other Items – Net	(231)	(148)	141	(59)
Income Tax Expense – Continuing Operations	$5,163	$6,521	$15,738	$14,602
Effective Income Tax Rate – Continuing Operations	26.1 %	29.3 %	26.1 %	25.3 %

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	40	236
Increases Related to Tax Positions for Current Year	26	131
Uncertain Positions Resolved During Year	(97)	—
Balance on September 30	$437	$589

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

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

16. Discontinued Operations

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

(in thousands)	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Operating Revenues	$ —	$ —	$ —	$ 24,623
Operating Expenses	(36)	420	(285)	31,770
Goodwill Impairment Charge	—	—	—	1,000
Operating Income (Loss)	36	(420)	285	(8,147)
Other Deductions	—	—	—	(42)
Income Tax Expense (Benefit)	14	(168)	114	(2,873)
Net Income (Loss) from Operations	22	(252)	171	(5,316)
(Loss) Gain on Disposition Before Taxes	—	(108)	—	11,425
Income Tax (Benefit) Expense on Disposition	—	(43)	—	4,493
Net (Loss) Gain on Disposition	—	(65)	—	6,932
Net Income (Loss)	$ 22	$ (317)	$ 171	$ 1,616

The above results for the nine months ended September 30, 2015 include net losses from operations of $4.1 million from Foley, $0.8 million from AEV, Inc. and $0.6 million, mainly related to the settlement of a warranty claim in the second quarter of 2015, from the Company's former waterfront equipment manufacturer, and net income of $0.2 million from the Company's former wind tower manufacturer related to a reduction in warranty reserves for expired warranties. Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges $4.4 million in the nine-month period ended September 30, 2015.

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

(in thousands)	September, 30 2016	December 31, 2015
Current Assets	$ 249	$ —
Assets of Discontinued Operations	$ 249	$ —
Current Liabilities	$ 1,631	$ 2,098
Liabilities of Discontinued Operations	$ 1,631	$ 2,098

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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	(24)	(115)
Decrease in Warranty Estimates for Prior Years	(530)	(100)
Warranty Reserve Balance, September 30	$1,549	$2,312

The warranty reserve balances as of September 30, 2016 relate entirely to products produced by the Company’s former wind tower and dock and boatlift manufacturing companies. Certain products sold by the companies carried one to fifteen year warranties. 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.

Expenses associated with remediation activities of these companies could be substantial. 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 net income and financial condition.

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

Results of Operations

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

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

Consolidated operating revenues were $197.2 million for the three months ended September 30, 2016 compared with $200.0 million for the three months ended September 30, 2015. Operating income was $27.3 million for the three months ended September 30, 2016 compared with $29.6 million for the three months ended September 30, 2015. The Company recorded diluted earnings per share from continuing operations of $0.37 for the three months ended September 30, 2016 compared with $0.42 for the three months ended September 30, 2015, and total diluted earnings per share of $0.37 for the three months ended September 30, 2016 compared with $0.41 for the three months ended September 30, 2015.

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

Intersegment Eliminations *(in thousands)*	September 30, 2016	September 30, 2015
Operating Revenues:		
Electric	$ 11	$ 29
Nonelectric	—	—
Cost of Products Sold	—	1
Other Nonelectric Expenses	11	28

Electric

(in thousands)	Three Months Ended September 30, 2016	2015	Change	% Change
Retail Sales Revenues	$87,755	$89,140	$(1,385)	(1.6)
Wholesale Revenues – Company Generation	1,656	377	1,279	339.3
Net Revenue – Energy Trading Activity	—	2	(2)	(100.0)
Other Revenues	13,312	11,048	2,264	20.5
Total Operating Revenues	$102,723	$100,567	$2,156	2.1
Production Fuel	14,789	11,124	3,665	32.9
Purchased Power – System Use	11,473	18,725	(7,252)	(38.7)
Other Operation and Maintenance Expenses	36,207	32,648	3,559	10.9
Depreciation and Amortization	13,408	11,190	2,218	19.8
Property Taxes	3,506	3,560	(54)	(1.5)
Operating Income	$23,340	$23,320	$20	0.1
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	1,095,236	1,082,062	13,174	1.2
Wholesale kwh Sales – Company Generation	61,244	22,116	39,128	176.9
Wholesale kwh Sales – Purchased Power Resold	—	10	(10)	(100.0)
Heating Degree Days	23	20	3	15.0
Cooling Degree Days	317	396	(79)	(19.9)

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

	Three Months ended September 30, 2016	2015
Cooling Degree Days	89.5 %	111.5 %

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

	Three Months ended September 30, 2016 vs Normal	2015 vs Normal	2016 vs 2015
Impact on Diluted Earnings Per Share	$(0.01)	$ 0.0	$ (0.01)

The $1.4 million decrease in retail revenue includes:

- A $3.8 million increase in retail revenue related to a 9.56% interim rate increase implemented in April 2016 in conjunction with Otter Tail Power Company's (OTP's) 2016 general rate increase request in Minnesota.

- A $1.2 million increase in Environmental Cost 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 $0.8 million increase in revenue related to increased kwh sales across all customer classes, offsetting the negative impact of milder weather on kwh sales and revenue.

- A $0.8 million increase in Conservation Improvement Program (CIP) cost recovery and incentive revenues.

- A $0.2 million increase in Transmission Cost Recovery (TCR) and Renewable Resource Adjustment (RRA) rider revenues related to increased investment in transmission plant and renewable energy resources.

more than offset by:

- A $5.3 million decrease in fuel and purchased power cost recovery revenues mainly due to a 48.3% decrease in kwhs purchased partially offset by a 28.3% increase in generation at a lower fuel-cost-per-kwh than the cost of purchased power.

- A $2.1 million reduction in interim rate revenues recorded to provide for an estimated refund related to a modification in OTP's original request and other expected outcomes in the pending Minnesota general rate case.

- A $0.8 million decrease in revenues from reduced demand due to milder weather in the third quarter of 2016, evidenced by a 19.9% decrease in cooling degree days compared to the third quarter of 2015.

Revenue from wholesale electric sales from company-owned generation increased $1.3 million while fuel costs for wholesale generation increased $0.8 million, resulting in a $0.5 million increase in wholesale revenue net of fuel costs.

Other electric revenues increased $2.3 million as a result of:

- A $2.7 million increase in Midcontinent Independent System Operator, Inc. (MISO) 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.
- A $0.6 million increase in MISO network integration transmission service revenues as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and becoming a member the Southwest Power Pool (SPP) in 2016.
- A $0.2 million increase in steam sales from Big Stone Plant to a nearby ethanol plant as a result of Big Stone Plant being fully operational in the third quarter of 2016 compared to operating in only August and September of 2015.

offset by:

- A $0.9 million decrease in revenue related to a reduction in work performed on projects for another regional transmission owner.
- A $0.4 million reduction in integrated transmission agreement revenues from two regional transmission providers related to the curtailment of services under an agreement with one provider and termination of an agreement with the other provider.

Production fuel costs increased $3.7 million as a result of a 40.5% increase in kwhs generated from our steam-powered and combustion turbine generators, related to Big Stone Plant and Coyote Station being fully operational in the third quarter of 2016. In the third quarter of 2015, Big Stone Plant was down for an extended maintenance outage and Coyote Station was operating at reduced load due to ongoing repairs related to a December 2014 boiler feed pump failure and fire.

The cost of purchased power to serve retail customers decreased $7.3 million due to a 48.3% decrease in kwhs purchased partially offset by an 18.6% increase in the cost per kwh purchased. The decrease in kwhs purchased was the result of increased availability and generation from company-owned resources. The increased cost per kwh purchased is related to contractual prices being paid for purchased power under a long-term supply agreement.

Electric operating and maintenance expenses increased $3.6 million as a result of:

- A $1.2 million increase in MISO transmission service charges due to increased transmission investment by other MISO members.
- A $0.9 million increase in operating supply and maintenance costs mainly related to increased generation at Coyote Station and Big Stone Plant and increased expenditures for vegetation maintenance.
- A $0.6 million increase in storm repair and other expenses mainly associated with excessive storm damage in OTP's Minnesota service area in July of 2016.
- A $0.6 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with Environmental Protection Agency (EPA) power plant emission regulations.
- A $0.5 million increase in transmission expenses from the SPP as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and becoming a member of the SPP in 2016.
- A $0.2 million increase in CIP program expenditures.

offset by:

- A $0.5 million decrease in costs related to a reduction in work performed on projects for another regional transmission owner.

Depreciation and amortization expense increased $2.2 million mainly due to the Big Stone Plant AQCS being placed in service in December 2015.

Manufacturing

	Three Months Ended September 30,			%
(in thousands)	2016	2015	Change	Change
Operating Revenues	$ 52,171	$ 52,460	$ (289)	(0.6)
Cost of Products Sold	40,616	40,961	(345)	(0.8)
Operating Expenses	5,246	5,094	152	3.0
Depreciation and Amortization	3,927	2,936	991	33.8
Operating Income	$ 2,382	$ 3,469	$ (1,087)	(31.3)

The $0.3 million decrease in revenues in our Manufacturing segment includes the following:

· Revenues at BTD Manufacturing, Inc. (BTD) increased $1.6 million, including:

o A $3.7 million increase in revenues at BTD-Georgia as a result of BTD acquiring and operating the Georgia plant in September 2015, compared with three months of operations in the third quarter of 2016.

offset by:

o A $2.1 million decrease in revenues at BTD's Minnesota and Illinois plants, mainly related to a decline in sales to manufacturers of recreational and agricultural equipment and heavy machinery due to softness in end markets served by those manufacturers.

· Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, decreased $1.9 million, including a $1.2 million decrease in industrial market sales and a $0.6 million decrease in revenues from sales of horticultural containers. The decrease in industrial market sales is primarily due to a continued decline in sales volumes to a customer insourcing product into its own manufacturing facilities.

The $0.3 million decrease in cost of products sold in our Manufacturing segment includes the following:

· Cost of products sold at BTD increased $0.3 million. This includes a $4.0 million increase in cost of products sold at BTD-Georgia, offset by a $3.7 million decrease in cost of products sold at BTD's other facilities. The $3.7 million decrease is related to the decrease in sales.

· Cost of products sold at T.O. Plastics decreased $0.6 million as a result of the reduction in sales.

Operating expenses at BTD increased $0.5 million, mainly in the areas of labor and benefit costs and computer-related expenditures, and included a $0.2 million increase in operating expenses at BTD-Georgia.

Operating expenses at T.O. Plastics decreased $0.4 million as a result of decreases in selling, benefits and administrative and general expenses.

The $1.0 million increase in depreciation and amortization expenses in our Manufacturing segment includes a $0.6 million increase at BTD-Georgia and a $0.5 million increase at BTD's Minnesota facilities as a result of placing new assets in service in Minnesota in 2015 and 2016, offset by a $0.1 million decrease at T.O. Plastics.

<u>Plastics</u>

	Three Months Ended September 30,			%
(in thousands)	2016	2015	Change	Change
Operating Revenues	$ 42,292	$ 47,025	$ (4,733)	(10.1)
Cost of Products Sold	34,789	37,468	(2,679)	(7.2)
Operating Expenses	2,346	2,655	(309)	(11.6)
Depreciation and Amortization	970	914	56	6.1
Operating Income	$ 4,187	$ 5,988	$ (1,801)	(30.1)

The $4.7 million decrease in Plastics segment revenues is the result of a 10.4% decrease in the price per pound of polyvinyl chloride (PVC) pipe sold, while quarter over quarter sales volume was essentially unchanged. The decline in sales price per pound is due to a continued softening in sales prices as a result of lower raw material prices. Increased pipe sales in Colorado and Utah and the Midwest and South-Central regions of the United States were mostly offset by decreased sales volumes in

California, Minnesota and North Dakota. Lower material costs, which did not decline as much as sales prices, resulted in a $2.7 million decrease in costs of product sold. The cost decrease in combination with a $0.3 million decrease in operating expenses did not offset the impact of lower pipe prices, resulting in a $1.8 million decrease in Plastics segment operating income.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower.

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.

	Three Months Ended September 30,			%
(in thousands)	2016	2015	Change	Change
Operating Expenses	$ 2,616	$ 3,050	(434)	(14.2)
Depreciation and Amortization	9	101	(92)	(91.1)

Corporate operating expenses decreased $0.4 million between the quarters mainly related to decreases in insurance costs related to reduced claims at our captive insurance company and reductions in accounting and legal fees, partially offset by an increase in employee benefit costs.

Interest Charges

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

Income Taxes – Continuing Operations

Income tax expense - continuing operations decreased $1.4 million in the three months ended September 30, 2016 compared with the three months ended September 30, 2015, mostly as a result of a $2.5 million reduction in income from continuing operations before income taxes. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three-month periods ended September 30:

(in thousands)	2016	2015
Income Before Income Taxes – Continuing Operations	$19,757	$22,230
Tax Computed at Company's Net Composite Federal and State Statutory Rate (39%)	7,705	8,670
Increases (Decreases) in Tax from:		
Federal Production Tax Credits	(1,423)	(1,437)
R&D Tax Credits	(223)	2
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(212)	(212)
Employee Stock Ownership Plan Dividend Deduction	(157)	(171)
Corporate Owned Life Insurance	(92)	185
Investment Tax Credits	(87)	(143)
Adjustment for Uncertain Tax Positions	(57)	281
AFUDC Equity	(51)	(144)
Section 199 Domestic Production Activities Deduction	(9)	(362)
Other Items – Net	(231)	(148)
Income Tax Expense – Continuing Operations	$5,163	$6,521
Effective Income Tax Rate – Continuing Operations	26.1 %	29.3 %

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 was essentially the same in the three months ended September 30, 2016 compared with the three months ended September 30, 2015. 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. 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 September 30:

(in thousands)	2016	2015
Operating Revenues	$—	$—
Operating Expenses	(36)	420
Operating Income (Loss)	36	(420)
Income Tax Expense (Benefit)	14	(168)
Net Income (Loss) from Operations	22	(252)
Loss on Disposition Before Taxes	—	(108)
Income Tax Benefit on Disposition	—	(43)
Net Loss on Disposition	—	(65)
Net Income (Loss)	$22	$(317)

Comparison of the Nine Months Ended September 30, 2016 and 2015

Consolidated operating revenues were $606.9 million for the nine months ended September 30, 2016 compared with $591.0 million for the nine months ended September 30, 2015. Operating income was $81.9 million for the nine months ended September 30, 2016 compared with $79.5 million for the nine months ended September 30, 2015. The Company recorded diluted earnings per share from continuing operations of $1.16 for the nine months ended September 30, 2016 compared to $1.15 for the nine months ended September 30, 2015 and total diluted earnings per share of $1.17 for the nine months ended September 30, 2016 compared to $1.19 for the nine months ended September 30, 2015.

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

Intersegment Eliminations *(in thousands)*	September 30, 2016	September 30, 2015
Operating Revenues:		
Electric	$ 27	$ 80
Nonelectric	—	4
Cost of Products Sold	—	5
Other Nonelectric Expenses	27	79

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Electric

(in thousands)	Nine Months Ended September 30, 2016	2015	Change	% Change
Retail Sales Revenues	$274,395	$272,258	$2,137	0.8
Wholesale Revenues – Company Generation	3,426	1,651	1,775	107.5
Net Revenue – Energy Trading Activity	—	187	(187)	(100.0)
Other Revenues	35,821	30,982	4,839	15.6
Total Operating Revenues	$313,642	$305,078	$8,564	2.8
Production Fuel	40,479	29,906	10,573	35.4
Purchased Power – System Use	43,486	62,101	(18,615)	(30.0)
Other Operation and Maintenance Expenses	115,206	107,929	7,277	6.7
Depreciation and Amortization	40,323	33,391	6,932	20.8
Property Taxes	10,774	10,324	450	4.4
Operating Income	$63,374	$61,427	$1,947	3.2
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	3,517,153	3,437,261	79,892	2.3
Wholesale kwh Sales – Company Generation	141,817	66,592	75,225	113.0
Wholesale kwh Sales – Purchased Power Resold	—	5,547	(5,547)	(100.0)
Heating Degree Days	3,277	3,779	(502)	(13.3)
Cooling Degree Days	450	479	(29)	(6.1)

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

	Nine Months ended September 30, 2016	2015
Heating Degree Days	82.1 %	93.7 %
Cooling Degree Days	97.6 %	103.0 %

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

	Nine Months ended September 30, 2016 vs Normal	2015 vs Normal	2016 vs 2015
Effect on Diluted Earnings Per Share	$ (0.05)	$ (0.01)	$ (0.04)

The $2.1 million increase in retail revenue includes:

- A $6.9 million increase in retail revenue related to a 9.56% interim rate increase implemented in April 2016 in conjunction with OTP's 2016 general rate increase request in Minnesota.
- A $3.2 million increase in ECR rider revenue due to the recovery of additional investment and costs related to the operation of the AQCS at Big Stone Plant that was placed in service in December 2015.
- A $2.7 million increase in revenue related to an increase in retail kwh sales, mainly to pipeline customers.
- A $2.0 million increase in CIP cost recovery and incentive revenues.
- A $1.9 million increase in TCR rider revenues related to increased investment in transmission plant.
- A $0.3 million increase in RRA rider revenues.

offset by:

- A $10.2 million decrease in fuel and purchased power cost recovery revenues mainly due to an 18.8% decrease in kwhs, purchased partially offset by a 22.2% increase in generation at a lower fuel-cost-per-kwh than the cost of purchased power.
- A $2.4 million decrease in revenues related to decreased consumption due to milder weather in the first nine months of 2016, evidenced by a 13.3% reduction in heating-degree days and 6.1% reduction in cooling-degree days compared to the first nine months of 2015.
- A $2.3 million reduction in interim rate revenues recorded to provide for an estimated refund related to a modification in OTP’s original request and other expected outcomes in the pending Minnesota general rate case.

Revenue from wholesale electric sales from company-owned generation increased $1.8 million while fuel costs for wholesale generation increased $1.4 million, resulting in a $0.4 million increase in wholesale revenue net of fuel costs as increased plant availability in 2016 has provided greater opportunity for OTP to respond to market demand.

Other electric revenues increased $4.8 million as a result of:

- A $4.9 million increase in MISO transmission tariff revenues related to increased investment in regional transmission lines and driven in part by returns on and recovery of CapX2020 and MISO designated MVP investment costs and operating expenses.

- A $0.7 million increase in steam sales to an ethanol plant near Big Stone Plant as a result of Big Stone Plant being fully operational in the first nine months of 2016 compared to being down for maintenance from March through July of 2015.

offset by:

- A $0.8 million decrease in revenue related to a reduction in work performed on projects for another regional transmission owner.

Production fuel costs increased $10.6 million as a result of a 33.2% increase in kwhs generated from our steam-powered and combustion turbine generators, mainly related to Big Stone Plant being fully operational in the first nine months of 2016. In 2015 Big Stone Plant was off line for maintenance from March through July.

The cost of purchased power to serve retail customers decreased $18.6 million due to an 18.8% decrease in kwhs purchased in combination with a 13.8% decrease in the cost per kwh purchased. Greater availability of company-owned generation in 2016 reduced the need to purchase electricity to serve retail load. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather and lower wholesale energy prices in the first nine months of 2016 compared with the first nine months of 2015.

Electric operating and maintenance expenses increased $7.3 million as a result of:

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$3.1 million in transmission expenses from the SPP beginning in 2016 as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the SPP.

- A $1.5 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with EPA power plant emission regulations.

- A $1.3 million increase in MISO transmission service charges due to increased transmission investment by other MISO members.

- A $1.3 million increase in CIP program expenditures.

- A $0.7 million increase in storm repair expenses mainly associated with excessive storm damage in OTP's Minnesota service area in July of 2016.

- A $0.6 million increase in operating supply expenses at Big Stone Plant and Coyote Station as generation at the plants increased in 2016.

- $0.5 million in expenditures incurred in 2016 to resolve customer rate issues.

offset by:

- A $1.0 million decrease in labor benefit costs related to a decrease in Corporate stock-based incentive expenses allocated to OTP.

- A $0.4 million decrease in costs related to a reduction in work performed on projects for another regional transmission owner.

- A $0.3 million reduction in other benefit related expenses.

Depreciation and amortization expense increased $6.9 million mainly due to the AQCS at Big Stone Plant being placed in service in December 2015 along with increased investment in transmission plant with the final phases of the Fargo-Monticello and Brookings-Southeast Twin Cities 345-kV transmission lines placed in service near the end of the first quarter of 2015.

The $0.5 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)	Nine Months Ended September 30, 2016	2015	Change	% Change
Operating Revenues	$170,443	$160,492	$9,951	6.2
Cost of Products Sold	129,929	126,185	3,744	3.0
Operating Expenses	16,581	16,256	325	2.0
Depreciation and Amortization	11,891	8,161	3,730	45.7
Operating Income	$12,042	$9,890	$2,152	21.8

The $10.0 million increase in revenues in our Manufacturing segment includes the following:

· Revenues at BTD increased $13.3 million, including:

o An $18.0 million increase in revenues at BTD-Georgia as a result of BTD acquiring and operating the Georgia plant in September of 2015 compared to nine months of operations in 2016.

o A $5.5 million increase in revenues mainly related to the production of wind tower components at BTD's Illinois plant.

offset by:

o A $10.0 million decrease in revenues related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.

o A $0.2 million decrease in revenues from sales of scrap metal due to a reduction in scrap metal prices.

· Revenues at T.O. Plastics decreased $3.3 million due to a reduction in industrial market sales primarily as a result of a continued decline in sales volumes to a customer insourcing product into its own manufacturing facilities.

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

- Cost of products sold at BTD increased $4.8 million. This includes a $16.2 million increase in cost of products sold at BTD-Georgia, offset by an $11.4 million net decrease in cost of products sold at BTD's other facilities. The $11.4 million decrease is related to the decrease in sales, partially offset by an increase in costs of products sold at BTD's Illinois plant as a result of the increase in the production of wind tower components.

- Cost of products sold at T.O. Plastics decreased $1.1 million related to the decrease in sales.

Gross margins at BTD were positively impacted in the first nine months of 2016 by changes in customer product mix between periods.

The $0.3 million increase in operating expenses in our Manufacturing segment includes the following:

- Operating expenses at BTD increased $1.2 million due to nine months of operations at BTD-Georgia in 2016 compared to one month in 2015.

- Operating expenses at T.O. Plastics decreased $0.9 million, primarily as a result of a $0.4 million decrease in selling expenses and a $0.4 decrease in incentive benefits.

The $3.7 million increase in depreciation and amortization expenses in our Manufacturing segment includes a $2.3 million increase at BTD-Georgia and a $1.5 million increase at BTD's other plants mainly as a result of placing new assets in service in Minnesota in 2015 and 2016.

Plastics

	Nine Months Ended September 30,				%
(in thousands)	2016	2015		Change	Change
Operating Revenues	$122,841	$125,531		$(2,690)	(2.1)
Cost of Products Sold	99,064	98,732		332	0.3
Operating Expenses	6,958	7,350		(392)	(5.3)
Depreciation and Amortization	2,880	2,625	&nb		