Otter Tail Corp
Form 10-Q
August 09, 2018

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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 June 30, 2018

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 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.:

Large accelerated filer	Accelerated filer	
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company	Emerging growth company

If an emerging growth company, indicate by checkmark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).

Yes No

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

July 31, 2018 – 39,664,883 Common Shares ($5 par value)

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OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands)	**June 30, 2018**	**December 31, 2017**
Assets		
Current Assets		
Cash and Cash Equivalents	$1,036	$16,216
Accounts Receivable:		
Trade—Net	91,780	68,466
Other	10,224	7,761
Inventories	90,435	88,034
Unbilled Receivables	18,278	22,427
Income Taxes Receivable	--	1,181
Regulatory Assets	17,914	22,551
Other	9,574	12,491
Total Current Assets	239,241	239,127
Investments	8,649	8,629
Other Assets	36,519	36,006
Goodwill	37,572	37,572
Other Intangibles—Net	13,075	13,765
Regulatory Assets	123,631	129,576
Plant		
Electric Plant in Service	1,993,738	1,981,018
Nonelectric Operations	223,323	216,937
Construction Work in Progress	168,372	141,067
Total Gross Plant	2,385,433	2,339,022
Less Accumulated Depreciation and Amortization	832,873	799,419
Net Plant	1,552,560	1,539,603

Total Assets	$2,011,247	$2,004,278

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	**June 30, 2018**	**December 31, 2017**
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	$20,977	$112,371
Current Maturities of Long-Term Debt	167	186
Accounts Payable	95,082	84,185
Accrued Salaries and Wages	18,460	21,534
Accrued Federal and State Income Taxes	673	--
Other Accrued Taxes	10,963	16,808
Regulatory Liabilities	7,248	9,688
Other Accrued Liabilities	12,665	11,389
Liabilities of Discontinued Operations	--	492
Total Current Liabilities	166,235	256,653
Pensions Benefit Liability	89,424	109,708
Other Postretirement Benefits Liability	70,203	69,774
Other Noncurrent Liabilities	25,060	22,769
Commitments and Contingencies (note 8)		
Deferred Credits		
Deferred Income Taxes	104,382	100,501
Deferred Tax Credits	20,676	21,379
Regulatory Liabilities	228,163	232,893
Other	2,563	3,329
Total Deferred Credits	355,784	358,102
Capitalization		
Long-Term Debt—Net	589,960	490,380
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, 2018—39,651,436 Shares; 2017—39,557,491 Shares	198,257	197,787
Premium on Common Shares	342,690	343,450
Retained Earnings	179,605	161,286
Accumulated Other Comprehensive Loss	(5,971)	(5,631)
Total Common Equity	714,581	696,892
Total Capitalization	1,304,541	1,187,272
Total Liabilities and Equity	$2,011,247	$2,004,278

See accompanying condensed notes to consolidated financial statements.

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Otter Tail Corporation Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	**Three Months Ended June 30, 2018**	**2017**	**Six Months Ended June 30, 2018**	**2017**
Operating Revenues				
Electric:				
Revenues from Contracts with Customers	$105,284	$102,655	$229,109	$222,437
Changes in Accrued Revenues under Alternative Revenue Programs	(1,565)	(424)	(2,440)	(1,663)
Total Electric Revenues	103,719	102,231	226,669	220,774
Product Sales under Contracts with Customers	122,629	109,855	240,945	205,429
Total Operating Revenues	226,348	212,086	467,614	426,203
Operating Expenses				
Production Fuel – Electric	15,888	12,477	34,594	28,859
Purchased Power – Electric	14,402	16,376	35,995	35,564
Electric Operation and Maintenance Expenses	37,741	36,748	77,216	74,025
Cost of Products Sold (depreciation included below)	93,545	84,013	182,330	159,290
Other Nonelectric Expenses	12,649	9,859	25,143	19,994
Depreciation and Amortization	18,745	17,908	37,508	35,762
Property Taxes – Electric	3,273	3,709	7,108	7,507
Total Operating Expenses	196,243	181,090	399,894	361,001
Operating Income	30,105	30,996	67,720	65,202
Interest Charges	7,676	7,527	15,048	14,989
Nonservice Cost Components of Postretirement Benefits	1,386	1,407	2,803	2,812
Other Income	707	552	1,890	1,105
Income Before Income Taxes – Continuing Operations	21,750	22,614	51,759	48,506
Income Tax Expense – Continuing Operations	3,054	5,897	6,848	12,260
Net Income from Continuing Operations	18,696	16,717	44,911	36,246
Discontinued Operations				
Income – net of Income Tax Expense of $0, $40, $0 and $78 for the respective periods	--	61	--	117
Net Income	18,696	16,778	44,911	36,363
Average Number of Common Shares Outstanding – Basic	39,605,717	39,462,865	39,578,296	39,406,834
	39,879,069	39,702,499	39,871,376	39,671,612

Average Number of Common Shares Outstanding – Diluted				
Basic Earnings Per Common Share:				
Continuing Operations	$0.47	$0.43	$1.13	$0.92
Discontinued Operations	--	--	--	--
	$0.47	$0.43	$1.13	$0.92
Diluted Earnings Per Common Share:				
Continuing Operations	$0.47	$0.42	$1.13	$0.92
Discontinued Operations	--	--	--	--
	$0.47	$0.42	$1.13	$0.92
Dividends Declared Per Common Share	$0.335	$0.320	$0.670	$0.640

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 June 30, 2018**	**2017**	**Six Months Ended June 30, 2018**	**2017**
Net Income	$18,696	$16,778	$44,911	$36,363
Other Comprehensive Income (Loss):				
Unrealized (Loss) Gain on Available-for-Sale Securities:				
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	--	(1)	(110)	(1)
Unrealized (Losses) Gains Arising During Period	(13)	21	(79)	38
Income Tax Benefit (Expense)	3	(7)	40	(13)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(10)	13	(149)	24
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 10)	233	159	460	316
Income Tax Expense	(61)	(63)	(120)	(126)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	--	--	(531)	--
Pension and Postretirement Benefit Plans – net-of-tax	172	96	(191)	190
Total Other Comprehensive Income (Loss)	162	109	(340)	214
Total Comprehensive Income	$18,858	$16,887	$44,571	$36,577

See accompanying condensed notes to consolidated financial statements.

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

(in thousands)	**Six Months Ended June 30, 2018**	**2017**
Cash Flows from Operating Activities		
Net Income	$44,911	$36,363
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Income from Discontinued Operations	--	(117)
Depreciation and Amortization	37,508	35,762
Deferred Tax Credits	(703)	(734)
Deferred Income Taxes	2,076	8,666
Change in Deferred Debits and Other Assets	10,309	8,075
Discretionary Contribution to Pension Plan	(20,000)	--
Change in Noncurrent Liabilities and Deferred Credits	(759)	(695)
Allowance for Equity/Other Funds Used During Construction	(1,060)	(401)
Stock Compensation Expense—Equity Awards	2,253	1,920
Other—Net	(193)	39
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(25,677)	(12,832)
Change in Inventories	(2,401)	(3,527)
Change in Other Current Assets	2,428	2,095
Change in Payables and Other Current Liabilities	1,433	(5,878)
Change in Interest and Income Taxes Receivable/Payable	3,470	590
Net Cash Provided by Continuing Operations	53,595	69,326
Net Cash Used in Discontinued Operations	(200)	(54)
Net Cash Provided by Operating Activities	53,395	69,272
Cash Flows from Investing Activities		
Capital Expenditures	(49,094)	(56,354)
Net Proceeds from Disposal of Noncurrent Assets	1,477	2,167
Cash Used for Investments and Other Assets	(2,102)	(2,431)
Net Cash Used in Investing Activities	(49,719)	(56,618)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	2,236	1,043
Net Short-Term (Repayments) Borrowings	(91,394)	15,234
Proceeds from Issuance of Common Stock	--	4,266

Common Stock Issuance Expenses	(108)	--
Payments for Retirement of Capital Stock	(2,450)	(1,799)
Proceeds from Issuance of Long-Term Debt	100,000	--
Short-Term and Long-Term Debt Issuance Expenses	(441)	--
Payments for Retirement of Long-Term Debt	(107)	(6,114)
Dividends Paid	(26,592)	(25,284)
Net Cash Used in Financing Activities	(18,856)	(12,654)
Net Change in Cash and Cash Equivalents	(15,180)	--
Cash and Cash Equivalents at Beginning of Period	16,216	--
Cash and Cash Equivalents at End of Period	$1,036	$--

See accompanying condensed notes to consolidated financial statements.

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OTTER TAIL CORPORATION

CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed notes thereto should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017. Because of seasonal and other factors, the earnings for the three- and six-month periods ended June 30, 2018 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, 2017.

1. Summary of Significant Accounting Policies

Revenue Recognition

In May 2014 the Financial Accounting Standards Board (FASB) issued a major update to the Accounting Standards Codification (ASC), Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). The Company adopted the updates in ASC 606 effective January 1, 2018 on a modified retrospective basis but did not record a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASC 606 had no material impact on the timing of revenue recognition for the Company or its subsidiaries. ASC 606 is a comprehensive, principles-based accounting standard which amended previous 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 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.

Due to the diverse business operations of the Company, recognition of revenue from contracts with customers depends on the product produced and sold or service performed. The Company recognizes revenue from contracts with customers, at prices that are fixed or determinable as evidenced by an agreement with the customer, when the Company has met its performance obligation under the contract and it is probable that the Company will collect the amount to which it is entitled in exchange for the goods or services transferred or to be transferred to the customer.

Depending on the product produced and sold or service performed and the terms of the agreement with the customer, the Company recognizes revenue either over time, in the case of delivery or transmission of electricity or related services or the production and storage of certain custom-made products, or at a point in time for the delivery of standardized products and other products made to the customers specifications where the terms of the contract require transfer of the completed product. Based on review of the Company's revenue streams, the Company has not identified any contracts where the timing of revenue recognition will change as a result of the adoption of the updates in ASC 606. Provisions for sales returns, early payment terms discounts, volume-based variable pricing incentives and warranty costs are recorded as reductions to revenue at the time revenue is recognized based on customer history, historical information and current trends.

In addition to recognizing revenue from contracts with customers under ASC 606, the Company also records adjustments to Electric segment revenues for amounts subject to future collection under alternative revenue programs (ARPs) as defined in ASC Topic 980, *Regulated Operations* (ASC 980). The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders on a separate line on the face of the Company's consolidated statements of income as they do not meet the criteria to be classified as revenue from contracts with customers.

Electric Segment Revenues—In the Electric segment, the Company recognizes revenue in two categories: (1) revenues from contracts with customers and (2) adjustments to revenues for amounts collectible under ARPs.

Most Electric segment revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by regulatory commissions in the states where Otter Tail Power Company (OTP) provides service. OTP also earns revenue from the transmission of electricity for others over the transmission assets it owns separately or jointly with other transmission service providers under rate tariffs established by the independent transmission system operator and approved by the Federal Energy Regulatory Commission (FERC). A third source of revenue for OTP comes from the generation and sale of electricity to wholesale customers at contract or market rates. Revenues from all these sources meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered or transmitted. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable rates. For electricity delivered and consumed after a meter is read but prior to the end of the reporting period, OTP records revenue and an unbilled receivable based on estimates of the kilowatt-hours (kwh) of energy delivered to the customer.

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ARPs provide for adjustments to rates outside of a general rate case proceeding, usually as a surcharge applied to future billings typically through the use of rate riders subject to periodic adjustments, to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public under public policy, laws or regulations. ARP riders generally provide for the recovery of specified costs and investments and include an incentive component to provide the regulated utility with a return on amounts invested. OTP has recovered costs and earned incentives or returns on investments subject to recovery under several ARP rate riders, including:

- In Minnesota: Transmission Cost Recovery (TCR), Environmental Cost Recovery (ECR), Renewable Resource Adjustment (RRA) and Conservation Improvement Program (CIP) riders.
- In North Dakota: TCR, ECR and RRA riders
- In South Dakota: TCR, ECR and Energy Efficiency Plan (conservation) riders.

OTP accrues ARP revenue on the basis of costs incurred, investments made and returns on those investments that qualify for recovery through established riders. Amounts billed under riders in effect at the time of the billing are included in revenues from contracts with customers net of amounts billed that are subject to refund through future rider adjustments. Amounts accrued and subject to recovery through future rider rate updates and adjustments are reported as ARP revenue adjustments on a separate line in the revenue section of the Company’s consolidated statement of income. See table in note 3 for total revenues billed and accrued under ARP riders for the three- and six-month periods ended June 30, 2018 and 2017.

Manufacturing Segment Revenues—Companies in the Manufacturing segment, BTD Manufacturing, Inc. (BTD) and T.O. Plastics, Inc. (T.O. Plastics), earn revenue predominantly from the production and delivery of custom-made or standardized parts to customers across several industries. BTD also earns revenue from the production and sale of tools and dies to other manufacturers. For the production and delivery of standardized products and other products made to the customers specifications where the terms of the contract require transfer of the completed product, the operating company has met its performance obligation and recognizes revenue at the point in time when the product is shipped and adjusts the revenue for volume rebate variable pricing considerations the company expects the customer will earn and for applicable early payment discounts the company expects the customer will take. For revenue recognized on products when shipped, the operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Plastics Segment Revenues—Companies in our Plastics segment earn revenue predominantly from the sale and delivery of standardized polyvinyl-chloride (PVC) pipe products produced at their manufacturing facilities. Revenue from the sale of these products is recognized at the point in time when the product is shipped based on prices agreed to in a purchase order. Billed amounts of revenue recognized are adjusted for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. For revenue recognized on shipped products, there is no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The Plastics segment has one customer for which it produces and stores a product made to the customer’s specifications and design under a build and hold agreement. For sales to this customer, the operating company recognizes revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. Ownership of the pipe transfers to the customer prior to delivery and the operating company is paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

See operating revenue table in note 2 for a disaggregation of the Company’s revenues by business segment for the three- and six-month periods ended June 30, 2018 and 2017.

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

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Fair Value Measurements

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

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

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

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

The following tables present, for each of the hierarchy levels, the Company’s assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2018 and December 31, 2017:

June 30, 2018 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$1,233		
Corporate Debt Securities – Held by Captive Insurance Company		$5,630	
Government-Backed and Government-Sponsored Enterprises’ Debt Securities – Held by Captive Insurance Company		1,527	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	945		
Total Assets	$2,178	$7,157	

December 31, 2017 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$1,285		
Corporate Debt Securities – Held by Captive Insurance Company		$5,373	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,787	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	823		
Total Assets	$2,108	$7,160	

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

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.

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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 paid by the Coyote Station owners under the LSA reflects 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.

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. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of June 30, 2018 could be as high as $55.7 million, OTP's 35% share of unrecovered costs.

Inventories

Inventories, valued at the lower of cost or net realizable value, consist of the following:

(in thousands)	June 30, 2018	December 31, 2017
Finished Goods	$27,140	$ 26,605
Work in Process	17,000	14,222
Raw Material, Fuel and Supplies	46,295	47,207
Total Inventories	$90,435	$ 88,034

Goodwill and Other Intangible Assets

An assessment of the carrying amounts of goodwill of the Company's operating units as of December 31, 2017 indicated the fair values are substantially in excess of their respective book values and not impaired.

The following table indicates there were no changes to goodwill by business segment during the first six months of 2018:

(in thousands)	Gross Balance December 31, 2017	Accumulated Impairments	Balance (net of impairments) December 31, 2017	Adjustments to Goodwill in 2018	Balance (net of impairments) June 30, 2018
Manufacturing	$ 18,270	$ --	$ 18,270	$ --	$ 18,270
Plastics	19,302	--	19,302	--	19,302
Total	$ 37,572	$ --	$ 37,572	$ --	$ 37,572

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

The following table summarizes the components of the Company's intangible assets at June 30, 2018 and December 31, 2017:

June 30, 2018 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 9,560	$ 12,931	18 - 206
Covenant not to Compete	590	557	33	2
Other	154	43	111	26
Total	$ 23,235	$ 10,160	$ 13,075	

December 31, 2017 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 8,994	$ 13,497	24 - 212
Covenant not to Compete	590	459	131	8
Other	154	17	137	32
Total	$ 23,235	$ 9,470	$ 13,765	

The amortization expense for these intangible assets was:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Amortization Expense – Intangible Assets	$345	$333	$690	$665

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

(in thousands)	2018	2019	2020	2021	2022
Estimated Amortization Expense – Intangible Assets	$1,315	$1,184	$1,133	$1,099	$1,099

Supplemental Disclosures of Cash Flow Information

	As of June 30,	
(in thousands)	2018	2017
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$11,564	$16,312

New Accounting Standards Adopted

ASU 2014-09—In May 2014 the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606).* The Company adopted the updates in ASC 606 effective January 1, 2018 on a modified retrospective basis. See disclosures above under Revenue Recognition.

ASU 2016-01—In January 2016 the FASB issued ASU No. 2016-01, *Financial Instruments—Overall (Subtopic 825-10)* (ASU 2016-01). The amendments in ASU 2016-01 address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments and require equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. For the Company, the amendments in ASU 2016-01 are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The Company adopted the updates in ASU 2016-01 in the first quarter of 2018, which results in changes in the fair value of equity instruments held as investments by the Company's captive insurance company being classified in net income.

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ASU 2017-07—In March 2017 the FASB issued ASU No. 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07), with the intent of improving the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715)*,* does not prescribe where the amount of net benefit cost should be presented in an employer's income statement and does not require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period, which the Company has provided in the electric operation and maintenance and other nonelectric expense lines on its income statement. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The Company has provided the amount of the non-service cost components of net periodic postretirement benefit costs in a separate line below interest expense on the face of its consolidated income statement. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments have been applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the Company's consolidated income statements and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

The majority of the Company's benefit costs to which the amendments in ASU 2017-07 apply are related to benefit plans in place at OTP, the Company's regulated provider of electric utility services. The amendments in ASU 2017-07 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs applicable to OTP, which require the capitalization of a portion of all the components of net periodic benefit costs be included in rate base additions and provide for rate recovery of the non-capitalized portion of all the components of net periodic pension costs as recoverable operating expenses. The Company has assessed the impact adoption of the amendments in ASU 2017-07 will have on its consolidated financial statements, financial position and results of operations and OTP has established regulatory assets to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under ASU 2017-07.

The Company's non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were $0.8 million. The Company's non-service costs components of net periodic postretirement benefit costs included in operating expense in 2017 and 2016 that will be reported in other income and deductions in the Company's 2018 Annual Report on Form 10-K after adoption of ASU 2017-07 were $5.6 million for 2017 and $5.1 million for 2016. Additional information on the allocation of postretirement benefit costs for the three and six-month periods ended June 30, 2018 and 2017 is provided in note 10 for the Company's major benefit programs presented.

New Accounting Standards Pending Adoption

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 Generally Accepted Accounting Principles in the United States (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 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 has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and is evaluating transition options. The Company does not plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

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ASU 2017-04—In January 2017 the FASB issued ASU No. 2017-04, *Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04), which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. In computing the implied fair value of goodwill under Step 2, an entity must perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the amendments in ASU 2017-04, an entity will perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized will not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity will consider income tax effects from any tax-deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

The amendments in ASU 2017-04 modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Because these amendments eliminate Step 2 from the goodwill impairment test, they should reduce the cost and complexity of evaluating goodwill for impairment. The amendments in ASU 2017-04 are effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017.

ASU 2018-02—In February 2018 the FASB issued ASU No. 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). The amendments in ASU 2018-02, which are narrow in scope, allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act (TCJA). Consequently, the amendments eliminate the stranded tax effects resulting from the TCJA and will improve the usefulness of information reported to financial statement users. The amendments in ASU 2018-02 also require certain disclosures about stranded tax effects and are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption of the amendments in ASU 2018-02 is permitted. The amendments in ASU 2018-02 can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company does not plan to adopt the amendments in ASU 2018-02 until the first quarter of 2019. On adoption, the Company will reclassify $0.8 million of income tax effects of the TCJA on the gross deferred tax amounts at the date of enactment of the TCJA related to items remaining in accumulated other comprehensive income from other comprehensive income to retained earnings so that the remaining gross deferred tax amounts related to items in other comprehensive income will reflect current effective tax rates.

2. Segment Information

Segment Information

The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. 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 Company's business structure currently includes the following three segments: Electric, Manufacturing and Plastics. The chart below indicates the companies included in each segment.

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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 plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing 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 2017. The Electric segment has one customer that provided 11.7% of 2017 Electric segment revenues. The Manufacturing segment has one customer that manufactures and sells recreational vehicles that provided 24.3% of 2017 Manufacturing segment revenues and one customer that manufactures and sells lawn and garden equipment that provided 12.0% of 2017 Manufacturing segment revenues. The Plastics segment has two customers that individually provided 20.6% and 17.8% of 2017 Plastics segment revenues. The loss of any one of these customers would have a significant negative impact on the financial position and results of operations of the respective business segment and the Company.

All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.2% and 98.3% of its operating revenues for the respective three-month periods ended June 30, 2018 and 2017, and 98.3% and 98.3% of its operating revenues for the respective six-month periods ended June 30, 2018 and 2017.

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three- and six-month periods ended June 30, 2018 and 2017 and total assets by business segment as of June 30, 2018 and December 31, 2017 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Electric Segment:				
Retail Sales Revenue from Contracts with Customers	$89,400	$86,679	$198,580	$193,133
Changes in Accrued ARP Revenues	(1,565)	(424)	(2,440)	(1,663)
Total Retail Sales Revenue	87,835	86,255	196,140	191,470
Wholesale Revenues – Company Generation	2,539	1,184	3,554	2,051
Other Revenues	13,351	14,797	26,996	27,266
Total Electric Segment Revenues	$103,725	$102,236	$226,690	$220,787
Manufacturing Segment:				
Metal Parts and Tooling	$57,388	$49,450	$114,315	$97,528
Plastic Products and Tooling	7,961	7,376	18,196	16,928
Other	2,805	2,478	4,305	3,265
Total Manufacturing Segment Revenues	$68,154	$59,304	$136,816	$117,721
Plastics Segment – Sale of PVC Pipe Products	$54,476	$50,551	$104,129	$87,708
Intersegment Eliminations	$(7)	$(5)	$(21)	$(13)
Total	$226,348	$212,086	$467,614	$426,203

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Interest Charges

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in thousands)	2018	2017	2018	2017
Electric	$6,687	$6,439	$13,077	$12,825
Manufacturing	555	553	1,109	1,107
Plastics	160	173	310	326
Corporate and Intersegment Eliminations	274	362	552	731
Total	$7,676	$7,527	$15,048	$14,989

Income Taxes

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in thousands)	2018	2017	2018	2017
Electric	$611	$2,442	$2,709	$8,504
Manufacturing	1,018	1,573	2,241	2,628
Plastics	2,207	2,858	4,621	4,248
Corporate	(782)	(976)	(2,723)	(3,120)
Total	$3,054	$5,897	$6,848	$12,260

Net Income (Loss)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in thousands)	2018	2017	2018	2017
Electric	$10,600	$10,134	$27,268	$25,694
Manufacturing	3,583	2,955	7,747	5,127
Plastics	6,229	4,637	13,073	7,074
Corporate	(1,716)	(1,009)	(3,177)	(1,649)
Discontinued Operations	--	61	--	117
Total	$18,696	$16,778	$44,911	$36,363

Identifiable Assets

(in thousands)	June 30, 2018	December 31, 2017
Electric	$1,687,799	$1,690,224
Manufacturing	181,094	167,023
Plastics	99,205	87,230
Corporate	43,149	59,801
Total	$2,011,247	$2,004,278

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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 FERC, impacting OTP's revenues in 2018 and 2017.

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 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., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of June 30, 2018 were approximately $99.4 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends 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–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties 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 was energized on September 8, 2017. OTP's capitalized costs on this project as of June 30, 2018 were approximately $72.5 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

General Rates—The MPUC rendered its final decision in OTP’s 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP’s allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%.

The MPUC’s order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVPs will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP’s Minnesota customers (see discussion under Minnesota Transmission Cost Recovery Rider below), and (2) approval of OTP’s proposal to transition rate base, expenses and revenues from ECR and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates were used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

OTP accrued interim and rider rate refunds until final rates became effective. The final interim rate refund, including interest, of $9.0 million was applied as a credit to Minnesota customers’ electric bills beginning November 17, 2017. In addition to the interim rate refund, OTP is currently refunding the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower 9.41% ROE approved in its 2016 general rate case going back to April 16, 2016, the date interim rates were implemented. As of October 31, 2017, the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were $0.9 million and $1.4 million, respectively. These amounts are being refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates, effective November 1, 2017, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

Minnesota Conservation Improvement Programs (MNCIP)—OTP recovers conservation-related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC. On May 25, 2016 the MPUC adopted the Minnesota Department of Commerce's (MNDOC's) proposed changes to the MNCIP financial incentive. The model provides 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. The financial incentive is also limited to 40% of 2017 MNCIP spending, 35% of 2018 spending and 30% of 2019 spending.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in an approximate 10% decrease in energy savings compared to 2016 program results. OTP requested approval for recovery of its 2017 MNCIP program costs not included in base rates, a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC on March 30, 2018. On June 13, 2018, in reply comments to a MNDOC recommendation for approval filed on May 30, 2018, OTP increased its request for a financial incentive to $2.9 million. On July 3, 2018 the MNDOC recommended the MPUC approve OTP's request with adjustment of the financial incentive to $2.6 million. In reply comments filed by OTP on July 13, 2018 OTP supported and reiterated its request for a $2.9 million financial incentive.

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 of new transmission facilities that meet certain criteria, plus a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule.

In OTP's 2016 general rate case order issued on May 1, 2017, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment resulted in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision would vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to jurisdictionally allocate costs of the FERC MVP transmission projects in the TCR rider.

On June 11, 2018 the Minnesota Court of Appeals reversed the MPUC's order related to the inclusion of Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in OTP Minnesota TCR revenue requirement calculations. On July 11, 2018 the MPUC filed a petition for review of the MVP decision to the Minnesota Supreme Court. If the Minnesota Court of Appeals opinion is upheld, OTP will file for an updated TCR rider rate to include the portion of revenue subject to recovery arising from the MISO MVP project investments and associated revenues. The amount that has been credited to Minnesota customers through the TCR through June 30, 2018, that would be subject to recovery should the Minnesota Court of Appeals decision be upheld, is approximately $2.0 million.

Environmental Cost Recovery Rider—OTP had an ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant Air Quality Control System (AQCS). The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. In its 2016 general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in November 2017.

Renewable Resource Adjustment—Effective November 1, 2017, with the implementation of final rates in Minnesota, new rates were put into effect for the Minnesota RRA rider to address recovery of revenue reductions for federal Production Tax Credits (PTCs) included in base rates that expired for one of OTP's wind farms in 2017 and 2018. OTP has requested an increase in the recoverable amount from $1.3 million to $5.8 million in its 2018 annual update to the RRA rider to be effective November 1, 2018.

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North Dakota

General Rates—On November 2, 2017 OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of $13.1 million or 8.72%. The $13.1 million increase is net of reductions in North Dakota RRA, TCR and ECR rider revenues that will result from a lower allowed rate of return on equity and changes in allocation factors in the general rate case. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. In response to the reduction in the federal corporate tax rate under the TCJA, the NDPSC issued an order on February 27, 2018 reducing OTP's annual revenue requirement for interim rates by $4.5 million to $8.3 million, effective March 1, 2018. OTP used the same rate of return on equity in the calculation of interim rates as the rate of return on equity used in its 2018 test-year rate request.

On March 23, 2018 OTP made a supplemental filing to its initial request for a rate review, reducing its request for an annual revenue increase from $13.1 million to $7.1 million, a 4.8% annual increase. The $6.0 million decrease includes $4.8 million related to tax reform and $1.2 million related to other updates. A settlement agreement among OTP, the NDPSC staff and intervenors was reached and submitted to the NDPSC for approval on July 6, 2018. The terms of the settlement agreement, which are nonbinding on the NDPSC's final decision, include an allowed rate of return on equity of 9.77% on a 52.5% equity to total capitalization capital structure and, along with other adjustments, provide for a $5.4 million net increase in annual revenues. This compares with OTP's March 2018 adjusted annual revenue increase request of $7.1 million (4.8%) and a return on equity of 10.3%. The settlement, if approved by the NDPSC, would result in no rate base adjustments from OTP's original request and allows for future rider recovery of the new Astoria natural gas-fired generating facility. The net revenue increase would also reflect a reduction in income tax recovery requirements related to the 2017 TCJA and decreases in rider revenue recovery requirements. OTP has accrued an interim rate refund of $1.8 million as of June 30, 2018 for amounts billed under interim rates in excess of amounts OTP would be entitled to under the terms of the proposed settlement agreement, which is pending acceptance by the NDPSC. OTP expects the NDPSC to decide on the rate case by the end of the third quarter.

OTP's previously approved 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 which enables OTP to recover its North Dakota jurisdictional share of investments in renewable energy facilities. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment.

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.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxic Standards (MATS) projects. The ECR rider provides for a return on investment at the level approved in OTP’s most recent general rate case and for recovery of OTP’s North Dakota share of reagent and emission allowance costs.

South Dakota

General Rates—On April 20, 2018 OTP filed a request with the SDPUC to increase non-fuel rates in South Dakota by approximately $3.3 million annually, or 10.1%, as the first step in a two-step request. Interim rates will be effective October 18, 2018. The full effects of the TCJA on South Dakota revenue requirements will be addressed in the rate case and incorporated into final rates at the conclusion of that case. The second step in the request is an additional 1.7% increase to recover costs for the proposed Merricourt wind generation facility when the facility goes into service.

OTP’s previously approved 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.

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Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.

Reagent Costs and Emission Allowances—The SDPUC has approved the recovery of reagent and emission allowance costs in OTP's South Dakota Fuel Clause Adjustment rider.

Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2016 for the rate riders described above:

Rate Rider	**R - Request Date** **A - Approval Date**	**Effective Date Requested or Approved**	***Annual Revenue ($000s)***	**Rate**
Minnesota				
Conservation Improvement Program				
2017 Incentive and Cost Recovery	R – March 30, 2018	October 1, 2018	$10,300	$0.00600/kwh
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	$9,868	$0.00536/kwh
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	$8,590	$0.00275/kwh
Transmission Cost Recovery				
2017 Rate Reset[1]	A – October 30, 2017	November 1, 2017	$(3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	$4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$7,203	Various
Environmental Cost Recovery				
2018 Annual Update	R – July 3, 2018	December 1, 2018	$--	0% of base
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$(1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	$11,884	6.927% of base
Renewable Resource Adjustment				
2018 Annual Update	R – June 14, 2018	November 1, 2018	$5,886	$.00244/kwh
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$1,279	$.00049/kwh
North Dakota				
Renewable Resource Adjustment				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	$9,650	7.493% of base
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	$9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	$9,262	7.573% of base
Transmission Cost Recovery				

2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	$7,469	Various
2017 Annual Update	A – November 29, 2017	January 1, 2018	$7,959	Various
2016 Annual Update	A – December 14, 2016	January 1, 2017	$6,916	Various
Environmental Cost Recovery				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	$7,718	5.593% of base
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$8,537	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	$9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	$10,359	7.904% of base
South Dakota				
Transmission Cost Recovery				
2017 Annual Update	A – February 28, 2018	March 1, 2018	$1,779	Various
2016 Annual Update	A – February 17, 2017	March 1, 2017	$2,053	Various
2015 Annual Update	A – February 12, 2016	March 1, 2016	$1,895	Various
Environmental Cost Recovery				
2017 Annual Update	A – October 13, 2017	November 1, 2017	$2,082	$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	$2,238	$0.00536/kwh

[1]*Approved on a provisional basis in the Minnesota general rate case docket and subject to revision in a separate docket.*

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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:

Revenues Recorded under Rider Rates

Rate Rider *(in thousands)*	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Minnesota				
Conservation Improvement Program Costs and Incentives[1]	$2,368	$2,102	$4,884	$4,068
Transmission Cost Recovery	(458)	1,273	(487)	3,443
Environmental Cost Recovery	(18)	2,812	(49)	5,636
Renewable Resource Recovery	659	--	1,184	--
North Dakota				
Renewable Resource Adjustment	2,079	1,839	4,046	3,609
Transmission Cost Recovery	1,165	1,384	3,227	3,895
Environmental Cost Recovery	1,830	2,388	3,651	4,876
South Dakota				
Transmission Cost Recovery	250	287	786	728
Environmental Cost Recovery	515	545	1,035	1,142
Conservation Improvement Program Costs and Incentives	122	176	351	416
Total	$8,512	$12,806	$18,628	$27,813

[1]*Includes MNCIP costs recovered in base rates.*

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to assess the impact to electric rates from the lower income tax rates under the TCJA and to develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018 but has not made a determination on rate treatment. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected after December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. As described above, OTP's pending general rate cases in North Dakota and South Dakota reflect the impact of the TCJA. OTP has accrued refund liabilities for revenues collected under rates set to recover higher levels of federal income taxes than OTP is currently incurring under the lower federal tax rates in the TCJA. As of June 30, 2018, accrued refund liabilities related to the tax rate reduction were $4.1 million in Minnesota, $0.8 million in North Dakota for amounts collected under interim rates in effect in January and February 2018, and $0.7 million in South Dakota.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935 (Federal Power Act). The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one-day suspension period, subject to ultimate approval by the FERC.

MVPs—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 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 sought to reduce the 12.38% ROE used in MISO’s transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners’ ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

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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%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, 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%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period in its February and June 2017 billings. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million on December 31, 2016 to $1.6 million as of June 30, 2018.

In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated and remanded the FERC's June 2014 ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the April 2017 action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On September 29, 2017 the MISO transmission owners filed a motion to dismiss the second complaint based on the D.C. Circuit decision in the NETOs complaint. If FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the second complaint and the ROE from the first complaint would remain in effect.

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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, environmental upgrades and conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

(in thousands)	June 30, 2018			Remaining Recovery/ Refund Period (months)
	Current	Long-Term	Total	
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$9,090	$ 107,946	$ 117,036	see below
Conservation Improvement Program Costs and Incentives[2]	3,927	4,163	8,090	27
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,907	6,907	asset lives
Deferred Marked-to-Market Losses[1]	2,862	1,574	4,436	30
Big Stone II Unrecovered Project Costs – Minnesota[1]	665	1,296	1,961	34
Debt Reacquisition Premiums[1]	231	856	1,087	171
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	513	--	513	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	392	492	59
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery[1]	--	422	422	asset lives
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	303	--	303	12
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	223	--	223	18
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	--	75	75	18
Total Regulatory Assets	$17,914	$ 123,631	$ 141,545	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$ 147,858	$ 147,858	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	79,835	79,835	asset lives
Refundable Fuel Clause Adjustment Revenues	4,972	--	4,972	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	716	--	716	4
North Dakota Renewable Resource Recovery Rider Accrued Refund	394	--	394	9
North Dakota Transmission Cost Recovery Rider Accrued Refund	319	--	319	12
Minnesota Southwest Power Pool Transmission Cost Recovery Tracker	--	316	316	see below
South Dakota Environmental Cost Recovery Rider Accrued Refund	308	--	308	12

North Dakota Environmental Cost Recovery Rider Accrued Refund	240	--	240	12
South Dakota Transmission Cost Recovery Rider Accrued Refund	231	--	231	12
Other	6	81	87	186
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	61	24	85	18
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	49	49	see below
Minnesota Renewable Resource Recovery Rider Accrued Refund	1	--	1	4
Total Regulatory Liabilities	$7,248	$228,163	$235,411	
Net Regulatory Asset/(Liability) Position	$10,666	$(104,532)	$(93,866)	

[1]*Costs subject to recovery excluding 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, 2017 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$9,090	$112,487	$121,577	see below
Conservation Improvement Program Costs and Incentives[2]	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses[1]	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota[1]	650	1,636	2,286	40
Debt Reacquisition Premiums[1]	254	960	1,214	177
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	75	--	75	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	442	542	65
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	309	--	309	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	--	1,985	1,985	24
North Dakota Renewable Resource Rider Accrued Revenues[2]	206	236	442	15
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	267	--	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	152	--	152	12
Total Regulatory Assets	$22,551	$129,576	$152,127	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$149,052	$149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Minnesota Southwest Power Pool Transmission Cost Tracker Refund	--	609	609	22
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
Other	5	84	89	192
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	--	802	10
Total Regulatory Liabilities	$9,688	$232,893	$242,581	
Net Regulatory Asset/(Liability) Position	$12,863	$(103,317)	$(90,454)	

[1]*Costs subject to recovery excluding 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.

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.

All Deferred Marked-to-Market Losses recorded as of June 30, 2018 relate to forward purchases of energy scheduled for delivery through December 2020.

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.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 171 months.

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Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues relate to revenues recorded for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to recovery from other Minnesota customers.

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 Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery are employee benefit-related costs that are required to be capitalized for ratemaking purposes and are recovered over the depreciable lives of the assets to which the related labor costs were applied.

North Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in North Dakota and are currently being recovered beginning with the establishment of interim rates in January 2018.

Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to amounts recoverable for investments in qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of June 30, 2018.

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.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that had not been billed to North Dakota customers as of December 31, 2017.

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

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that had not been billed to North Dakota customers as of December 31, 2017.

The regulatory liability related to Deferred Income Taxes results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

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

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of June 30, 2018.

The North Dakota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of June 30, 2018.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of June 30, 2018.

The Minnesota Southwest Power Pool Transmission Cost Tracker Refund relates to revenues billed for recovery of these transmission costs in excess of actual costs incurred that are subject to refund.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of June 30, 2018.

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 and for reagent and emission allowances costs that are recoverable from North Dakota customers as of June 30, 2018.

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The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of June 30, 2018.

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 were subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of June 30, 2018.

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 were refundable to Minnesota customers as of December 31, 2017.

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

Reconciliation of Common Shareholders' Equity

(in thousands)	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Equity
Balance, December 31, 2017	$197,787	$343,450	$161,286	$ (5,631)	$696,892
Common Stock Issuances, Net of Expenses	767	(860)			(93)

Common Stock Retirements	(297)	(2,153)			(2,450)
Net Income			44,911		44,911
Other Comprehensive Loss				(340)	(340)
Employee Stock Incentive Plans Expense		2,253			2,253
Common Dividends ($0.67 per share)			(26,592)		(26,592)
Balance, June 30, 2018	$198,257	$342,690	$179,605	$ (5,971)	$714,581

Shelf Registrations and Common Share Distribution Agreement

On May 3, 2018 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) 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, which expires on May 3, 2021. On May 3, 2018, the Company also filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares under the Company's Automatic Dividend Reinvestment (DRIP) and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. The shelf registration for the Plan expires on May 3, 2021. The shelf registration statements replaced the Company’s prior shelf registration statements which expired on May 11, 2018. On May 1, 2018 the Company’s Distribution Agreement with J.P. Morgan Securities (JPMS) ended as required under the agreement. The Company expects to establish a new ATM offering program under which the Company may offer and sell its common shares from time to under the shelf registration statement.

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Common Shares

Following is a reconciliation of the Company’s common shares outstanding from December 31, 2017 through June 30, 2018:

Common Shares Outstanding, December 31, 2017	39,557,491
Issuances:	
Executive Stock Performance Awards (2015 shares earned)	114,648
Vesting of Restricted Stock Units	19,950
Restricted Stock Issued to Directors	18,200
Directors Deferred Compensation	578
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(59,431)
Common Shares Outstanding, June 30, 2018	39,651,436

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three- and six-month periods ended June 30, 2018 and 2017. 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 June 30		Six Months ended June 30	
	2018	2017	2018	2017
Weighted Average Common Shares Outstanding – Basic	39,605,717	39,462,865	39,578,296	39,406,834
Plus Outstanding Share Awards net of Share Reductions for Unrecognized Stock-Based Compensation Expense and Excess Tax Benefits:				
Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers based on Measurement Period-to-Date Performance	202,643	173,974	212,902	187,806
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	57,616	50,087	58,373	53,980
Nonvested Restricted Shares	10,733	12,719	19,188	19,894
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	2,360	2,854	2,617	3,098
Total Dilutive Shares	273,352	239,634	293,080	264,778
Weighted Average Common Shares Outstanding – Diluted	39,879,069	39,702,499	39,871,376	39,671,612

The effect of dilutive shares on earnings per share for the three- and six-month periods ended June 30, 2018 and 2017, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in any of the periods.

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6. Share-Based Payments

Stock Incentive Awards

The following stock incentive awards were granted under the 2014 Stock Incentive Plan during the six-month period ended June 30, 2018:

Award	Grant-Date	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Stock Performance Awards Granted to Executive Officers	February 5, 2018	54,000	$ 35.73	December 31, 2020
Restricted Stock Units Granted to Executive Officers	February 5, 2018	15,200	$ 41.325	25% per year through February 6, 2022
Restricted Stock Units Granted to Key Employees	April 9, 2018	12,945	$ 38.45	100% on April 8, 2022
Restricted Stock Units Granted to Key Employee	June 20, 2018	1,000	$ 42.46	100% on April 8, 2022
Restricted Stock Granted to Nonemployee Directors	April 9, 2018	18,200	$ 43.40	33% per year through April 8, 2021

Under the performance share awards the aggregate award for performance at target is 54,000 shares. For target performance the participants would earn an aggregate of 27,000 common shares for achieving the target set for the Company’s 3-year average adjusted return on equity. The participants would also earn an aggregate of 27,000 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, 2018 through December 31, 2020, 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, 2018 and the average closing price for the 20 trading days immediately preceding January 1, 2021. Actual payment may range from zero to 150% of the target amount, or up to 81,000 common shares. There are no voting or dividend rights related to these awards until the shares, if any, are issued at the end of the performance measurement period. 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 an officer who is party to an Executive Employment Agreement with the Company is to be made at target at the date of any such event. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 718, and will be measured over the performance period based on the grant-date fair value of the award. The grant-date fair value of each performance share award was determined using a Monte Carlo fair valuation simulation model.

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration 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 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 was based on the average of the high and low market price 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 respective vesting periods.

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 the average of the high and low market price of one share of the Company's common stock on the date of grant.

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

As of June 30, 2018, the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $6.2 million (before income taxes) which will be amortized over a weighted-average period of 2.2 years.

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Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three- and six-month periods ended June 30, 2018 and 2017 are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Stock Performance Awards Granted to Executive Officers	$668	$425	$1,319	$1,074
Restricted Stock Units Granted to Executive Officers	173	104	422	368
Restricted Stock Granted to Executive Officers	--	16	16	38
Restricted Stock Granted to Nonemployee Directors	165	144	331	272
Restricted Stock Units Granted to Key Employees	101	81	165	168
Totals	$1,107	$770	$2,253	$1,920

7. Retained Earnings and Dividend Restriction

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

Both the Company and OTP credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of June 30, 2018, the Company was in compliance with these financial 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, the 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 47.4% and 58.0% based on OTP's 2017 capital structure petition approved by order of the MPUC on September 1, 2017. As of June 30, 2018, OTP's equity-to-total-capitalization ratio including short-term debt was 52.5% and its net assets restricted from distribution totaled approximately $473,000,000. Total capitalization for OTP cannot currently exceed $1,178,024,000.

On May 1, 2018 OTP filed a petition for approval of an equity-to-total capitalization ratio between 47.9% and 58.5% in its 2018 capital structure filing currently pending before MPUC. If approved, total capitalization for OTP will not be allowed to exceed $1,204,416,000. On June 15, 2018 the MNDOC provided initial comments recommending the MPUC approve OTP's petition with additional reporting requirements.

8. Commitments and Contingencies

Construction and Other Purchase Commitments

At June 30, 2018 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019 of approximately $45.3 million. At December 31, 2017 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019 of approximately $41.0 million. At June 30, 2018 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $5.8 million. At December 31, 2017 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $6.7 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 2041. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Coyote Station expire at the end of 2040. OTP's current coal purchase agreements for Big Stone Plant expire at the end of 2020. OTP entered into a coal purchase agreement with Peabody COALSALES, LLC effective May 14, 2018 for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2020. OTP has no fixed minimum purchase requirements under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement, except for the purchase of a portion of Big Stone Plant's coal requirements contracted to be purchased in 2018 and 2019 under existing agreements with Contura Coal Sales, LLC. OTP has an all-requirements agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. OTP has no fixed minimum purchase requirements under this agreement.

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Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. In the first quarter of 2018, OTP entered into an agreement to lease rail cars for transporting coal to Hoot Lake Plant. The lease period runs from May 2018 through June 2021, increasing OTP’s commitments under operating leases by $216,000 in 2018, $324,000 in 2019, $324,000 in 2020 and $162,000 in 2021. The Company’s nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment. In June 2018 BTD entered into an agreement to lease manufacturing and warehouse space in a building near its Georgia plant for a term of 63 months from July 2018 through September 2023, increasing its commitments under operating leases by approximately $79,000 in 2018, $322,000 in 2019, $332,000 in 2020, $342,000 in 2021, $352,000 in 2022 and $271,000 in 2023.

Contingencies

OTP had a $1.6 million refund liability on its balance sheet as of June 30, 2018 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate.

Together with as many as 200 utilities, generators and power marketers, OTP participated in 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 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO’s application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC’s decision to not resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC’s orders were reviewed in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involved multiple petitioners and intervenors including OTP. On June 28, 2018 the D.C. Circuit rendered a final decision denying the appellants petitions for review of the FERC’s orders and decision to not order a resettlement of the markets based on MISO application of the RSG rate to market participants. Requests for rehearing were due by July 30, 2018. No requests for rehearing were filed.

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. In addition to the ROE refund described earlier, the most significant contingencies impacting the Company’s consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed the established reserve amounts and litigation matters. Should all of these known items, excluding the ROE refund liability already recognized, result in liabilities being incurred, the loss could be as high as $1.0 million.

In 2014 the Environmental Protection Agency (EPA) published both proposed standards of performance for carbon dioxide (CO_2) emissions from new, reconstructed and modified fossil fuel-fired power plants (New Source Performance Standards), and proposed CO_2 emission guidelines for existing fossil fuel-fired power plants (the Clean Power Plan) under Section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. Both rules were challenged on legal grounds. On February 9, 2016 the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the Clean Power Plan on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO_2 rules discussed above. Thereafter, the EPA issued notices in the Federal Register of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the New Source Performance Standards and the Clean Power Plan, pending EPA review. On October 16, 2017 the EPA published a proposed rule to rescind the Clean Power Plan. Therefore, there is uncertainty regarding the future of both rules.

Other

The Company is a party to litigation and regulatory enforcement matters arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of June 30, 2018 will not be material.

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9. Short-Term and Long-Term Borrowings

The following table presents the status of the Company's lines of credit as of June 30, 2018 and December 31, 2017:

(in thousands)	Line Limit	In Use on June 30, 2018	Restricted due to Outstanding Letters of Credit	Available on June 30, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	$130,000	$6,102	$ --	$123,898	$130,000
OTP Credit Agreement	170,000	14,875	300	154,825	57,329
Total	$300,000	$20,977	$ 300	$278,723	$187,329

Debt Issuances

2018 Note Purchase Agreement

On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $100 million aggregate principal amount of OTP's 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the Note Purchase Agreement, any prepayment made by OTP of all of the Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants. The 2018 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2018 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

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The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2018 and December 31, 2017:

June 30, 2018 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$14,875	$ 6,102	$ 20,977
Long-Term Debt:			
3.55% Guaranteed Senior Notes, due December 15, 2026		$ 80,000	$ 80,000
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
Senior Unsecured Notes 4.07%, Series 2018A, due February 7, 2048	100,000		100,000
North Dakota Development Note, 3.95%, fully repaid April 1, 2018		--	--
PACE Note, 2.54%, due March 18, 2021		604	604
Total	$512,000	$ 80,604	$ 592,604
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	167	167
Unamortized Long-Term Debt Issuance Costs	2,045	432	2,477
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$509,955	$ 80,005	$ 589,960
Total Short-Term and Long-Term Debt (with current maturities)	$524,830	$ 86,274	$ 611,104

December 31, 2017 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$112,371	$ --	$ 112,371
Long-Term Debt:			
Term Loan, LIBOR plus 0.90%, due February 5, 2018		$ --	$ --
3.55% Guaranteed Senior Notes, due December 15, 2026		80,000	80,000
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		27	27
PACE Note, 2.54%, due March 18, 2021		684	684

Total	$412,000	$ 80,711	$ 492,711
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	186	186
Unamortized Long-Term Debt Issuance Costs	1,684	461	2,145
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$410,316	$ 80,064	$ 490,380
Total Short-Term and Long-Term Debt (with current maturities)	$522,687	$ 80,250	$ 602,937

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10. 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 June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Service Cost—Benefit Earned During the Period	$1,615	$1,407	$3,230	$2,814
Interest Cost on Projected Benefit Obligation	3,363	3,536	6,726	7,070
Expected Return on Assets	(5,299)	(4,807)	(10,599)	(9,614)
Amortization of Prior-Service Cost:				
From Regulatory Asset	4	29	8	59
From Other Comprehensive Income[1]	--	1	--	2
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,783	1,272	3,567	2,545
From Other Comprehensive Income[1]	47	32	91	63
Net Periodic Pension Cost[2]	$1,513	$1,470	$3,023	$2,939
[1]Corporate cost included in nonservice cost components of postretirement benefits.				
[2]Allocation of Costs:				
Costs included in OTP capital expenditures	*$379*	*$286*	*$707*	*$571*
Service costs included in electric operation and maintenance expenses	*1,195*	*1,100*	*2,442*	*2,200*
Service costs included in other nonelectric expenses	*40*	*34*	*80*	*68*
Nonservice costs capitalized as regulatory assets	*(24)*	*--*	*(45)*	*--*
Nonservice costs included in nonservice cost components of postretirement benefits	*(77)*	*50*	*(161)*	*100*

Cash flows—The Company had no minimum funding requirement as of December 31, 2017 but made discretionary plan contributions totaling $20 million in the first quarter of 2018.

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 June	Six Months Ended June 30,

(in thousands)	30, 2018	2017	2018	2017
Service Cost—Benefit Earned During the Period	$100	$72	$200	$145
Interest Cost on Projected Benefit Obligation	399	421	798	843
Amortization of Prior-Service Cost:				
From Regulatory Asset	4	4	8	8
From Other Comprehensive Income[1]	9	10	19	19
Amortization of Net Actuarial Loss:				
From Regulatory Asset	67	72	134	143
From Other Comprehensive Income[1]	165	110	330	220
Net Periodic Pension Cost[2]	$744	$689	$1,489	$1,378
[1]*Amortization of prior service costs and net actuarial losses from other comprehensive income are included in nonservice cost components of postretirement benefits on the face of the Company's consolidated statements of income.*				
[2]*Allocation of Costs:*				
Service costs included in electric operation and maintenance expenses	*$25*	*$23*	*$50*	*$47*
Service costs included in other nonelectric expenses	*75*	*49*	*150*	*98*
Nonservice costs included in nonservice cost components of postretirement benefits	*644*	*617*	*1,289*	*1,233*

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Service Cost—Benefit Earned During the Period	$381	$356	$763	$712
Interest Cost on Projected Benefit Obligation	646	678	1,291	1,356
Amortization of Net Actuarial Loss:				
From Regulatory Asset	412	233	824	466
From Other Comprehensive Income[1]	11	6	21	12
Net Periodic Postretirement Benefit Cost[2]	$1,450	$1,273	$2,899	$2,546
Effect of Medicare Part D Subsidy	$(36)	$(140)	$(73)	$(280)
[1]*Corporate cost included in nonservice cost components of postretirement benefits.*				
[2]*Allocation of Costs:*				
Costs included in OTP capital expenditures	*$89*	*$248*	*$167*	*$495*
Service costs included in electric operation and maintenance expenses	*283*	*279*	*577*	*557*
Service costs included in other nonelectric expenses	*9*	*8*	*19*	*17*
Nonservice costs capitalized as regulatory assets	*251*	*--*	*468*	*--*
Nonservice costs included in nonservice cost components of postretirement benefits	*818*	*738*	*1,668*	*1,477*

11. Fair Value of Financial Instruments

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

Cash Equivalents—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of June 30, 2018 and December 31, 2017 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.50% 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 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.

	June 30, 2018		December 31, 2017	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$1,036	$1,036	$16,216	$16,216
Short-Term Debt	(20,977)	(20,977)	(112,371)	(112,371)
Long-Term Debt including Current Maturities	(590,127)	(605,185)	(490,566)	(543,691)

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13. 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 June 30,		Six Months Ended June 30,	
(in thousands)	2018	2017	2018	2017
Income Before Income Taxes – Continuing Operations	$21,750	$22,614	$51,759	$48,506
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26% for 2018, 39% for 2017)	$5,655	$8,819	$13,457	$18,917
Increases (Decreases) in Tax from:				
Property Related Differences and Other Regulatory Adjustments	(1,025)	35	(2,098)	140
Federal Production Tax Credits	(930)	(2,010)	(2,050)	(4,062)
Excess Tax Deduction – Equity Method Stock Awards	--	--	(624)	(697)
Other Comprehensive Income Deferred Tax Rate Adjustment	--	--	(531)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(213)	(516)	(425)
Research and Development and Other Tax Credits	(202)	(190)	(409)	(387)
Allowance for Funds Used During Construction – Equity	(111)	(91)	(278)	(158)
Employee Stock Ownership Plan Dividend Deduction	(99)	(172)	(199)	(345)
Section 199 Domestic Production Activities Deduction	--	(330)	--	(660)
Other Items – Net	24	49	96	(63)
Income Tax Expense – Continuing Operations	$3,054	$5,897	$6,848	$12,260
Effective Income Tax Rate – Continuing Operations	14.0 %	26.1 %	13.2 %	25.3 %

The following table summarizes the activity related to the Company's unrecognized tax benefits:

(in thousands)	2018	2017
Balance on January 1	$684	$891
Decreases Related to Tax Positions for Prior Years	(44)	--
Increases Related to Tax Positions for Current Year	72	147
Uncertain Positions Resolved During Year	--	--
Balance on June 30	$712	$1,038

The balance of unrecognized tax benefits as of June 30, 2018 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2018 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of June 30, 2018.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of August 1, 2018, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2014 for federal, Minnesota and North Dakota income taxes.

The Company recognized the income tax effects of the TCJA in its 2017 consolidated financial statements in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC Topic 740, *Income Taxes*, and allowed up to one year to complete the required analyses and accounting for the TCJA. At December 31, 2017 the Company was able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, changes to bonus depreciation and consequences on the Company's regulatory liabilities. The final impact of the TCJA may differ from these estimates due to, among other things, changes in the Company's interpretations and assumptions, and additional guidance that may be issued by the U.S. Internal Revenue Service, and rate regulators. As of June 30, 2018 the Company has not made any adjustments to the amounts recorded at December 31, 2017.

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

Results of Operations

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three- and six-month periods ended June 30, 2018 and 2017, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2018 and our business outlook for the remainder of 2018.

Comparison of the Three Months Ended June 30, 2018 and 2017

Consolidated operating revenues were $226.3 million for the three months ended June 30, 2018 compared with $212.1 million for the three months ended June 30, 2017. Operating income was $30.1 million for the three months ended June 30, 2018 compared with $31.0 million for the three months ended June 30, 2017. The Company recorded diluted earnings per share from continuing operations and in total of $0.47 for the three months ended June 30, 2018 compared with $0.42 for the three months ended June 30, 2017.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three-month periods ended June 30, 2018 and 2017 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)*	June 30, 2018	June 30, 2017
Operating Revenues:		
Electric	$ 6	$ 5
Nonelectric	1	--
Costs of Products Sold	2	2
Other Nonelectric Expenses	5	3

Electric

(in thousands)	Three Months Ended June 30, 2018	2017	Change	% Change
Retail Sales Revenues from Contracts with Customers	$89,400	$86,679	$2,721	3.1
Changes in Accrued Revenues under Alternative Revenue Programs	(1,565)	(424)	(1,141)	(269.1)
Total Retail Sales Revenue	$87,835	$86,255	$1,580	1.8
Wholesale Revenues – Company Generation	2,539	1,184	1,355	114.4
Other Revenues	13,351	14,797	(1,446)	(9.8)
Total Operating Revenues	$103,725	$102,236	$1,489	1.5
Production Fuel	15,888	12,477	3,411	27.3
Purchased Power – System Use	14,402	16,376	(1,974)	(12.1)
Other Operation and Maintenance Expenses	37,741	36,748	993	2.7
Depreciation and Amortization	13,979	13,094	885	6.8
Property Taxes	3,273	3,709	(436)	(11.8)
Operating Income	$18,442	$19,832	$(1,390)	(7.0)
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	1,136,326	1,073,689	62,637	5.8
Wholesale kwh Sales – Company Generation	95,475	45,308	50,167	110.7
Heating Degree Days	675	420	255	60.7
Cooling Degree Days	228	96	132	137.5

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

	Three Months ended June 30,	
	2018	2017
Heating Degree Days	133.7 %	80.9 %
Cooling Degree Days	221.4 %	90.6 %

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions in the second quarter of 2018 and 2017 and between the quarters:

	2018 vs Normal	2017 vs Normal	2018 vs 2017
Effect on Diluted Earnings Per Share	$ 0.04	$ (0.01)	$0.05

The $1.6 million increase in retail revenue includes:

A $2.5 million increase in revenues related to increased consumption due to colder weather in April of 2018 and warmer weather in May and June of 2018 compared with the same periods in 2017, evidenced by a 60.7% increase in heating degree days and 137.5% increase in cooling degree days between the quarters.

A $1.9 million increase in revenue related to increased mwh sales to an industrial customer.

A $1.4 million increase in retail revenue, net of an estimated refund of $0.5 million, related to an interim rate increase implemented in January 2018 in conjunction with Otter Tail Power Company's (OTP) 2017 general rate increase request in North Dakota.

A $0.9 million increase in North Dakota and Minnesota Renewable Resource Adjustment (RRA) rider revenues related to the expiration of federal production tax credit (PTC) eligibility on one of OTP's wind farms, which increases revenue requirements under the RRAs.

A $0.2 million net increase in Conservation Improvement Program (CIP) cost recovery and incentive revenues.

offset by:

- A $2.4 million reduction in revenues for the provision of refunds related to the excess recovery of federal income taxes currently in Minnesota and South Dakota retail electric rates resulting from the 2017 Tax Cuts and Jobs Act (TCJA).

- A $1.3 million reduction in revenues related to implementation of final rates in Minnesota that were lower than interim rates in effect in the second quarter of 2017.

- A $1.0 million decrease in retail revenue related to the recovery of fuel and purchased power costs due to a 19.4% reduction in higher-cost kwhs purchased to serve retail customers.

- A $0.6 million decrease in North Dakota and South Dakota Environmental Cost Recovery (ECR) rider revenues related to less federal taxes being recovered through the riders due to the TCJA and a lower investment balance in environmental upgrades due to depreciation.

Wholesale electric revenues increased $1.4 million due to a 111% increase in wholesale kwh sales and a 1.8% increase in wholesale electric prices. Increased demand and higher wholesale prices combined with increased availability of OTP generating units provided greater opportunity for economic dispatch and wholesale energy sales in the second quarter of 2018 compared with the second quarter of 2017.

Other electric revenues decreased $1.4 million mainly due to a $1.1 million load resettlement payment received from another regional transmission provider in the second quarter of 2017 while no similar resettlement was recorded in the second quarter of 2018.

Production fuel costs increased $3.4 million, mainly due to a 46.9% increase in kwhs generated from OTP’s fuel burning plants to provide electricity for the increase in retail and wholesale demand driven by greater deviations from normal weather in our service territory in the second quarter of 2018 compared with the second quarter of 2017.

The cost of purchased power to serve retail customers decreased $2.0 million in relation to a 19.4% decrease in kwhs purchased due to higher market prices and increased availability of and sourcing from company-owned generating units.

Electric operating and maintenance expenses increased $1.0 million due to increases of $1.4 million in labor related expenses, mainly pension and medical benefit costs for both retired and active employees, $0.5 million in CIP expenditures and $0.4 million in storm repair expenses related to damages caused by severe weather in June 2018, offset by a $1.2 million decrease in transmission service charges. The decrease in transmission service charges reflects reductions of $0.8 million in Southwest Power Pool transmission service costs and $0.4 million in MISO transmission costs incurred by OTP between quarters.

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Property tax expense decreased $0.4 million due to lower tax valuations.

Depreciation expense increased $0.9 million mainly due to an increase in transmission project unitization and the Big Stone South-Brookings transmission line being placed in service in September 2017.

Manufacturing

(in thousands)	Three Months Ended June 30, 2018	2017	Change	% Change
Operating Revenues	$68,154	$59,304	$8,850	14.9
Cost of Products Sold	51,844	44,735	7,109	15.9
Operating Expenses	7,439	5,646	1,793	31.8
Depreciation and Amortization	3,760	3,874	(114)	(2.9)
Operating Income	$5,111	$5,049	$62	1.2

The $8.9 million increase in revenues in our Manufacturing segment includes the following:

Revenues at BTD Manufacturing, Inc. (BTD) increased $8.3 million, including increases in parts sales of $3.0 million to manufacturers of recreational vehicles, $2.7 million to manufacturers of agricultural equipment and $2.1 million to manufacturers of heavy construction equipment. The revenue increase also included a $0.5 million increase in revenue from scrap metal sales due to higher scrap volumes from increased production and a 5% increase in scrap metal pricing.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, improved $0.6 million due to increases of $0.4 million from sales of horticultural containers and $0.2 million from sales of industrial products.

The $7.1 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased $6.6 million in relationship to increased parts sales.

Cost of products sold at T.O. Plastics increased $0.5 million related to the increase in product sales.

The $1.8 million increase in operating expenses in our Manufacturing segment includes a $1.8 million increase in expenses at BTD resulting from increases in labor and benefit costs due to additional employees and increases in contracted services and computer and software expenses.

Plastics

(in thousands)	Three Months Ended June 30, 2018	2017	Change	% Change
Operating Revenues	$54,476	$50,551	$3,925	7.8
Cost of Products Sold	41,703	39,280	2,423	6.2
Operating Expenses	3,262	2,705	557	20.6
Depreciation and Amortization	954	931	23	2.5
Operating Income	$8,557	$7,635	$922	12.1

Plastics segment revenues increased $3.9 million due to a 12.3% increase in polyvinyl-chloride (PVC) pipe prices offset by a 4.0% decrease in pounds of PVC pipe sold. The increase in revenue was partially offset by a $2.4 million increase in cost of products sold, despite the decrease in sales volume, due to a 10.6% increase in costs per pound of pipe sold. The increase in pipe prices in excess of the increase in cost of products sold resulted in a $1.5 million increase in gross margin. Plastics segment operating expenses increased by $0.6 million mainly due to an increase in incentives.

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Corporate

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

(in thousands)	Three Months Ended June 30, 2018	2017	Change	% Change
Operating Expenses	$1,953	$1,511	$ 442	29.3
Depreciation and Amortization	52	9	43	477.8

Corporate operating expenses increased $0.4 million due to higher short- and long-term incentive costs.

Income Taxes – Continuing Operations

Income tax expense - continuing operations decreased $2.8 million in the three months ended June 30, 2018 compared with the three months ended June 30, 2017 mainly due to the reduction in the federal income tax rate from 35% to 21% under the TCJA, and also due to a $0.9 million decrease in income from continuing operations before income taxes. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three-month periods ended June 30, 2018 and 2017:

(in thousands)	Three Months Ended June 30, 2018	2017
Income Before Income Taxes – Continuing Operations	$21,750	$22,614
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26% for 2018, 39% for 2017)	$5,655	$8,819
Increases (Decreases) in Tax from:		
Property Related Differences and Other Regulatory Adjustments	(1,025)	35
Federal Production Tax Credits (PTCs)	(930)	(2,010)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(213)

Research and Development and Other Tax Credits	(202)	(190)
Allowance for Funds Used During Construction – Equity	(111)	(91)
Employee Stock Ownership Plan Dividend Deduction	(99)	(172)
Section 199 Domestic Production Activities Deduction	--	(330)
Other Items – Net	24	49
Income Tax Expense – Continuing Operations	$3,054	$5,897
Effective Income Tax Rate – Continuing Operations	14.0 %	26.1 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP’s kwh generation from its wind turbines eligible for PTCs decreased 51.1% in the three months ended June 30, 2018 compared with the three months ended June 30, 2017 due to the PTC eligibility period ending for one of OTP’s wind farms. 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.

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Comparison of the Six Months Ended June 30, 2018 and 2017

Consolidated operating revenues were $467.6 million for the six months ended June 30, 2018 compared with $426.2 million for the six months ended June 30, 2017. Operating income was $67.7 million for the six months ended June 30, 2018 compared with $65.2 million for the six months ended June 30, 2017. The Company recorded diluted earnings per share from continuing operations and in total of $1.13 for the six months ended June 30, 2018 compared with $0.92 for the six months ended June 30, 2017.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the six-month periods ended June 30, 2018 and 2017 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)*	June 30, 2018	June 30, 2017
Operating Revenues:		
Electric	$ 21	$ 13
Costs of Products Sold	7	3
Other Nonelectric Expenses	14	10

Electric

	Six Months Ended June 30,			%
(in thousands)	2018	2017	Change	Change
Retail Sales Revenues from Contracts with Customers	$ 198,580	$ 193 133	$ 5,447	2.8
Changes in Accrued Revenues under Alternative Revenue Programs	(2,440)	(1,663)	(777)	(46.7)
Total Retail Sales Revenue	$ 196,140	$ 191,470	$ 4,670	2.4
Wholesale Revenues – Company Generation	3,554	2,051	1,503	73.3
Other Revenues	26,996	27,266	(270)	(1.0