

UNITED STATES SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2019

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission file number 0-53713

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota 27-0383995  
(State or other jurisdiction of (I.R.S. Employer  
incorporation or organization) Identification No.)

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

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

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

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares, par value \$5.00 per share	OTTR	The Nasdaq Stock Market LLC

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 every Interactive Data File required to be submitted 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 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

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:

**October 31, 2019 – 39,759,054 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)

<i>(in thousands)</i>	<b>September 30, 2019</b>	<b>December 31, 2018</b>
<b>ASSETS</b>		

<b>Current Assets</b>				
Cash and Cash Equivalents	\$	921	\$	861
Accounts Receivable:				
Trade—Net		92,189		75,144
Other		8,884		9,741
Inventories		97,052		106,270
Unbilled Receivables		19,020		23,626
Income Taxes Receivable		-		2,439
Regulatory Assets		12,667		17,225
Other		6,926		6,114
Total Current Assets		237,659		241,420
<b>Investments</b>		9,743		8,961
<b>Other Assets</b>		38,996		35,759
<b>Goodwill</b>		37,572		37,572
<b>Other Intangibles—Net</b>		11,562		12,450
<b>Regulatory Assets</b>		130,551		135,257
<b>Right of Use Assets - Operating Leases</b>		21,953		-
<b>Plant</b>				
Electric Plant in Service		2,189,732		2,019,721
Nonelectric Operations		238,542		228,120
Construction Work in Progress		141,839		181,626
Total Gross Plant		2,570,113		2,429,467
Less Accumulated Depreciation and Amortization		877,958		848,369
Net Plant		1,692,155		1,581,098
<b>Total Assets</b>	\$	2,180,191	\$	2,052,517

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail Corporation**  
**Consolidated Balance Sheets**  
(not audited)

<i>(in thousands, except share data)</i>	<b>September 30, 2019</b>	<b>December 31, 2018</b>		
<b>LIABILITIES AND EQUITY</b>				
<b>Current Liabilities</b>				
Short-Term Debt	\$	108,997	\$	18,599
Current Maturities of Long-Term Debt		180		172
Accounts Payable		89,360		96,291
Accrued Salaries and Wages		19,151		24,857
Accrued Federal and State Income Taxes		3,945		-
Other Accrued Taxes		13,828		17,287
Regulatory Liabilities		6,311		738
Current Operating Lease Liabilities		4,006		-
Other Accrued Liabilities		7,409		12,149
Total Current Liabilities		253,187		170,093
<b>Pensions Benefit Liability</b>		75,363		98,358
<b>Other Postretirement Benefits Liability</b>		73,668		71,561

<b>Long-Term Operating Lease Liabilities</b>	18,384	-
<b>Other Noncurrent Liabilities</b>	28,130	24,326
<b>Commitments and Contingencies (note 9)</b>		
<b>Deferred Credits</b>		
Deferred Income Taxes	124,602	120,976
Deferred Tax Credits	18,963	19,974
Regulatory Liabilities	238,781	226,469
Other	2,593	1,895
<b>Total Deferred Credits</b>	<b>384,939</b>	<b>369,314</b>
<b>Capitalization</b>		
Long-Term Debt—Net	590,015	590,002
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, 2019—39,755,277 Shares; 2018—39,664,884 Shares	198,776	198,324
Premium on Common Shares	346,294	344,250
Retained Earnings	215,931	190,433
Accumulated Other Comprehensive Loss	(4,496)	(4,144)
<b>Total Common Equity</b>	<b>756,505</b>	<b>728,863</b>
<b>Total Capitalization</b>	<b>1,346,520</b>	<b>1,318,865</b>
<b>Total Liabilities and Equity</b>	<b>\$ 2,180,191</b>	<b>\$ 2,052,517</b>

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail Corporation**  
**Consolidated Statements of Income**  
(not audited)

<i>(in thousands, except share and per-share amounts)</i>	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Operating Revenues</b>				
Electric:				
Revenues from Contracts with Customers	\$ 115,285	\$ 105,749	\$ 346,291	\$ 334,858
Changes in Accrued Revenues under Alternative Revenue Programs	(921)	(317)	(1,601)	(2,757)
<b>Total Electric Revenues</b>	<b>114,364</b>	<b>105,432</b>	<b>344,690</b>	<b>332,101</b>
Product Sales under Contracts with Customers	114,288	122,230	359,137	363,175
<b>Total Operating Revenues</b>	<b>228,652</b>	<b>227,662</b>	<b>703,827</b>	<b>695,276</b>
<b>Operating Expenses</b>				
Production Fuel – Electric	18,331	17,129	45,547	51,723
Purchased Power – Electric System Use	13,163	9,664	54,748	45,659
Electric Operation and Maintenance Expenses	35,869	33,897	114,107	111,113
Cost of Products Sold (depreciation included below)	88,747	93,361	277,325	275,691
Other Nonelectric Expenses	11,665	12,547	38,404	37,690
Depreciation and Amortization	19,657	18,708	58,229	56,216
Property Taxes – Electric	3,965	4,094	11,824	11,202

Total Operating Expenses	191,397	189,400	600,184	589,294
<b>Operating Income</b>	<b>37,255</b>	<b>38,262</b>	<b>103,643</b>	<b>105,982</b>
<b>Interest Charges</b>	<b>7,539</b>	<b>7,549</b>	<b>23,190</b>	<b>22,597</b>
<b>Nonservice Cost Components of Postretirement Benefits</b>	<b>1,055</b>	<b>1,326</b>	<b>3,165</b>	<b>4,129</b>
<b>Other Income</b>	<b>1,020</b>	<b>1,245</b>	<b>3,114</b>	<b>3,135</b>
<b>Income Before Income Taxes</b>	<b>29,681</b>	<b>30,632</b>	<b>80,402</b>	<b>82,391</b>
<b>Income Tax Expense</b>	<b>4,936</b>	<b>7,359</b>	<b>13,907</b>	<b>14,207</b>
<b>Net Income</b>	<b>\$ 24,745</b>	<b>\$ 23,273</b>	<b>\$ 66,495</b>	<b>\$ 68,184</b>
<b>Average Number of Common Shares Outstanding – Basic</b>	<b>39,714,672</b>	<b>39,621,524</b>	<b>39,694,677</b>	<b>39,592,705</b>
<b>Average Number of Common Shares Outstanding – Diluted</b>	<b>39,946,739</b>	<b>39,903,565</b>	<b>39,922,580</b>	<b>39,882,105</b>
<b>Basic Earnings Per Common Share</b>	<b>\$ 0.62</b>	<b>\$ 0.59</b>	<b>\$ 1.68</b>	<b>\$ 1.72</b>
<b>Diluted Earnings Per Common Share</b>	<b>\$ 0.62</b>	<b>\$ 0.58</b>	<b>\$ 1.67</b>	<b>\$ 1.71</b>

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail Corporation**  
**Consolidated Statements of Comprehensive Income**  
(not audited)

<i>(in thousands)</i>	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2019</b>	<b>2018</b>	<b>2019</b>	<b>2018</b>
<b>Net Income</b>	\$ 24,745	\$ 23,273	\$ 66,495	\$ 68,184
<b>Other Comprehensive Income (Loss):</b>				
Unrealized Gain (Loss) on Available-for-Sale Securities:				
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(1)	4	(5)	(106)
Unrealized Gains (Losses) Arising During Period	30	(14)	187	(93)
Income Tax (Expense) Benefit	(6)	2	(38)	42
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	23	(8)	144	(157)
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	130	232	389	692
Income Tax Expense	(34)	(60)	(101)	(180)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	-	-	-	(531)
Pension and Postretirement Benefit Plans – net-of-tax	96	172	288	(19)
<b>Total Other Comprehensive Income (Loss)</b>	<b>119</b>	<b>164</b>	<b>432</b>	<b>(176)</b>
<b>Total Comprehensive Income</b>	<b>\$ 24,864</b>	<b>\$ 23,437</b>	<b>\$ 66,927</b>	<b>\$ 68,008</b>

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail Corporation**  
**Consolidated Statements of Common Shareholders' Equity**  
**For the Three- and Nine-Month Periods Ended September 30, 2019 and 2018**  
(not audited)

<i>(in thousands, except common shares outstanding)</i>	<b>Common Shares</b>	<b>Par Value, Common</b>	<b>Premium on</b>	<b>Retained Earnings</b>	<b>Accumulated Other</b>	<b>Total Common</b>
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	Outstanding	Shares	Common Shares		Comprehensive Income/(Loss)	Equity
<b>Balance, June 30, 2019</b>	<b>39,754,902</b>	<b>\$ 198,775</b>	<b>\$ 345,030</b>	<b>\$ 205,115</b>	<b>\$ (4,615)</b>	<b>\$ 744,305</b>
Common Stock Issuances, Net of Expenses	375	1	(37)			(36)
Net Income				24,745		24,745
Other Comprehensive Income					119	119
Employee Stock Incentive Plan Expense			1,301			1,301
Common Dividends (\$0.35 per share)				(13,929)		(13,929)
<b>Balance, September 30, 2019</b>	<b>39,755,277</b>	<b>\$ 198,776</b>	<b>\$ 346,294</b>	<b>\$ 215,931</b>	<b>\$ (4,496)</b>	<b>\$ 756,505</b>
<b>Balance, June 30, 2018</b>	<b>39,651,436</b>	<b>\$ 198,257</b>	<b>\$ 342,690</b>	<b>\$ 179,605</b>	<b>\$ (5,971)</b>	<b>\$ 714,581</b>
Common Stock Issuances, Net of Expenses	25,225	126	(126)			-
Common Stock Retirements	(11,777)	(59)	(503)			(562)
Net Income				23,273		23,273
Other Comprehensive Loss					164	164
Employee Stock Incentive Plan Expense			1,149			1,149
Common Dividends (\$0.335 per share)				(13,303)		(13,303)
<b>Balance, September 30, 2018</b>	<b>39,664,884</b>	<b>\$ 198,324</b>	<b>\$ 343,210</b>	<b>\$ 189,575</b>	<b>\$ (5,807)</b>	<b>\$ 725,302</b>
<b>Balance, December 31, 2018</b>	<b>39,664,884</b>	<b>\$ 198,324</b>	<b>\$ 344,250</b>	<b>\$ 190,433</b>	<b>\$ (4,144)</b>	<b>\$ 728,863</b>
Common Stock Issuances, Net of Expenses	145,617	728	(747)			(19)
Common Stock Retirements	(55,224)	(276)	(2,454)			(2,730)
Net Income				66,495		66,495
Other Comprehensive Income					432	432
ASU 2018-02 2017 TCJA Stranded Tax Transfer				784	(784)	-
Employee Stock Incentive Plan Expense			5,245			5,245
Common Dividends (\$1.05 per share)				(41,781)		(41,781)
<b>Balance, September 30, 2019</b>	<b>39,755,277</b>	<b>\$ 198,776</b>	<b>\$ 346,294</b>	<b>\$ 215,931</b>	<b>\$ (4,496)</b>	<b>\$ 756,505</b>
<b>Balance, December 31, 2017</b>	<b>39,557,491</b>	<b>\$ 197,787</b>	<b>\$ 343,450</b>	<b>\$ 161,286</b>	<b>\$ (5,631)</b>	<b>\$ 696,892</b>
Common Stock Issuances, Net of Expenses	178,601	893	(986)			(93)
Common Stock Retirements	(71,208)	(356)	(2,656)			(3,012)
Net Income				68,184		68,184
Other Comprehensive Loss					(176)	(176)
Employee Stock Incentive Plan Expense			3,402			3,402
Common Dividends (\$1.005 per share)				(39,895)		(39,895)
<b>Balance, September 30, 2018</b>	<b>39,664,884</b>	<b>\$ 198,324</b>	<b>\$ 343,210</b>	<b>\$ 189,575</b>	<b>\$ (5,807)</b>	<b>\$ 725,302</b>

<i>(in thousands)</i>	<b>Nine Months Ended September 30,</b>	
	<b>2019</b>	<b>2018</b>
<b>Cash Flows from Operating Activities</b>		
Net Income	\$ 66,495	\$ 68,184
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	58,229	56,216
Deferred Tax Credits	(1,011)	(1,054)
Deferred Income Taxes	3,487	7,529
Change in Deferred Debits and Other Assets	7,142	10,641
Discretionary Contribution to Pension Plan	(22,500)	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	10,344	(191)
Allowance for Equity/Other Funds Used During Construction	(1,602)	(1,586)
Stock Compensation Expense—Equity Awards	5,245	3,402
Other—Net	312	(201)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(16,213)	(27,804)
Change in Inventories	9,218	(6,581)
Change in Other Current Assets	2,974	3,827
Change in Payables and Other Current Liabilities	(20,744)	5,546
Change in Interest and Income Taxes Receivable/Payable	3,773	2,932
<b>Net Cash Provided by Operating Activities</b>	<b>105,149</b>	<b>100,860</b>
<b>Cash Flows from Investing Activities</b>		
Capital Expenditures	(149,695)	(74,489)
Net Proceeds from Disposal of Noncurrent Assets	4,111	1,879
Cash Used for Investments and Other Assets	(5,546)	(3,324)
<b>Net Cash Used in Investing Activities</b>	<b>(151,130)</b>	<b>(75,934)</b>
<b>Cash Flows from Financing Activities</b>		
Change in Checks Written in Excess of Cash	383	(7)
Net Short-Term Borrowings (Repayments)	90,398	(96,882)
Payments for Retirement of Capital Stock and Common Stock Issuance Expenses	(2,765)	(3,120)
Proceeds from Issuance of Long-Term Debt	-	100,000
Short-Term and Long-Term Debt Issuance Expenses	(66)	(441)
Payments for Retirement of Long-Term Debt	(128)	(148)
Dividends Paid	(41,781)	(39,895)
<b>Net Cash Provided by (Used in) Financing Activities</b>	<b>46,041</b>	<b>(40,493)</b>
<b>Net Change in Cash and Cash Equivalents</b>	<b>60</b>	<b>(15,567)</b>
<b>Cash and Cash Equivalents at Beginning of Period</b>	<b>861</b>	<b>16,216</b>
<b>Cash and Cash Equivalents at End of Period</b>	<b>\$ 921</b>	<b>\$ 649</b>

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, 2018. Because of seasonal and other factors, the earnings for the three- and nine-months ended September 30, 2019 should not be taken as an indication of earnings for all or any part of the balance of the year.

#### 1. Summary of Significant Accounting Policies

### Revenue Recognition

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 customer's specifications where the terms of the contract require transfer of the completed product. 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 Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (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.

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.

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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), Energy Intensive Trade Exposed and Conservation Improvement Program riders.
- In North Dakota: TCR, ECR, RRA and Generation Cost Recovery (GCR) riders.
- In South Dakota: TCR, ECR, Phase-in Rate Plan 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 changes in accrued revenues under ARPs 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 nine-month periods ended September 30, 2019 and 2018.

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 customer 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. For revenue recognized on products when shipped, the operating companies have no further obligation to provide services related to such products. 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. 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 nine-month periods ended September 30, 2019 and 2018.

### 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.

### 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.



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

The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of September 30, 2019 and December 31, 2018:

<b>September 30, 2019</b> (in thousands)	Level 1	Level 2	Level 3
<b>Assets:</b>			
Investments:			
Equity Funds – Held by Captive Insurance Company	\$ 1,462		
Corporate Debt Securities – Held by Captive Insurance Company		\$ 3,378	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		4,772	
Other Assets:			
Money Market and Mutual Funds – Retirement Plans	2,661		
<b>Total Assets</b>	<b>\$ 4,123</b>	<b>\$ 8,150</b>	

<b>December 31, 2018</b> (in thousands)	Level 1	Level 2	Level 3
<b>Assets:</b>			
Investments:			
Equity Funds – Held by Captive Insurance Company	\$ 1,294		
Corporate Debt Securities – Held by Captive Insurance Company		\$ 5,898	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,586	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	838		
<b>Total Assets</b>	<b>\$ 2,132</b>	<b>\$ 7,484</b>	

The level 2 fair values for Government-Backed and Government-Sponsored Enterprises' and Corporate Debt Securities Held by the Company's Captive Insurance Company 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.

#### 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 September 30, 2019 could be as high as \$51.3 million, OTP's 35% share of unrecovered costs.

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Inventories

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

<i>(in thousands)</i>	September 30, 2019	December 31, 2018
Finished Goods	\$ 29,601	\$ 37,130
Work in Process	18,884	20,393
Raw Material, Fuel and Supplies	48,567	48,747
Total Inventories	\$ 97,052	\$ 106,270

Goodwill and Other Intangible Assets

An assessment of the carrying amounts of goodwill of the Company's operating units as of December 31, 2018 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 nine months of 2019:

<i>(in thousands)</i>	Gross Balance December 31, 2018	Accumulated Impairments	Balance (net of impairments) December 31, 2018	Adjustments to Goodwill in 2019	Balance (net of impairments) September 30, 2019
Manufacturing	\$ 18,270	\$ -	\$ 18,270	\$ -	\$ 18,270
Plastics	19,302	-	19,302	-	19,302
Total	\$ 37,572	\$ -	\$ 37,572	\$ -	\$ 37,572

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

The following table summarizes the components of the Company's intangible assets at September 30, 2019 and December 31, 2018:

<b>September 30, 2019</b> <i>(in thousands)</i>	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
<b>Amortizable Intangible Assets:</b>				
Customer Relationships	\$ 22,491	\$ 10,976	\$ 11,515	3 - 191
Other	154	107	47	11
Total	\$ 22,645	\$ 11,083	\$ 11,562	

<b>December 31, 2018</b> <i>(in thousands)</i>	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
<b>Amortizable Intangible Assets:</b>				
Customer Relationships	\$ 22,491	\$ 10,127	\$ 12,364	12 - 200
Other	154	68	86	20
Total	\$ 22,645	\$ 10,195	\$ 12,450	

The amortization expense for these intangible assets was:

<i>(in thousands)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Amortization Expense – Intangible Assets	\$ 296	\$ 329	\$ 888	\$ 1,019

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

<i>(in thousands)</i>	2019	2020	2021	2022	2023
Estimated Amortization Expense – Intangible Assets	\$ 1,184	\$ 1,133	\$ 1,099	\$ 1,099	\$ 1,099

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Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of September 30,	
	2019	2018
<b>Noncash Investing Activities:</b>		
Transactions Related to Capital Additions not Settled in Cash	\$ 15,893	\$ 12,059

New Accounting Standards Adopted

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 supersedes the requirements under ASC Topic 840 on leases and requires the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. 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. The Company adopted the amendments in ASU 2016-02 to its consolidated financial statements effective January 1, 2019. See note 8 for further information on leases and the Company's elections for applying the new standard.

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/(loss) (AOCI/(L)) to retained earnings for the stranded tax effects resulting from the 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. 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 adopted the updates in ASU 2018-02 effective January 1, 2019, applying them in the period of adoption and not retrospectively. On adoption, the Company reclassified \$784,000 of income tax effects of the TCJA on the gross deferred tax amounts reflected in AOCI/(L) at the date of enactment of the TCJA from AOCI/(L) to retained earnings so the remaining gross deferred tax amounts related to items in AOCI/(L) will reflect current effective tax rates.

Support for the determination of the stranded tax effects resulting from the enactment of the TCJA in AOCI/(L) is provided in the table below.

<i>(in thousands)</i>	Unrealized Gains on Available-for- Sale Securities	Unamortized Actuarial Losses and Prior Service Costs on Pension and Other Postretirement Benefits	AOCI/(L)
Balance on December 22, 2017 – Pre-tax	\$ 71	\$ (5,672)	\$ (5,601)
Effect of TCJA 14% Federal Tax Rate Reduction on Gross Deferred Tax Amounts	\$ 10	\$ (794)	\$ (784)

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.



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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. The Company early adopted the amendments in ASU 2017-04 in the first quarter of 2019. The Company had no indication that any of its goodwill was impaired, therefore, the adoption of the updated standard had no impact on the Company's consolidated financial statements.

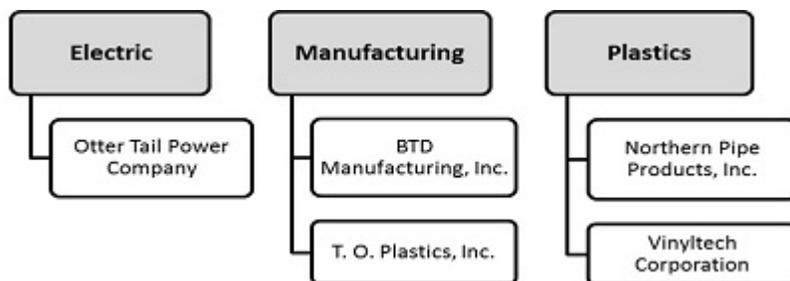
### New Accounting Standards Pending Adoption

ASU 2016-13—In June 2016 the FASB issued ASU No. 2016-13, *Financial Instruments—Credit Losses (Topic 326)* (ASC Topic 326), which changes how entities account for credit losses on receivables and certain other assets. The guidance requires use of a current expected loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after December 15, 2019. The Company does not expect adoption of the new standard to have a material impact on its consolidated financial statements.

ASU 2018-15—In August 2018 the FASB issued ASU No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40)*, which amends ASC 350-40, *Internal-Use Software*, to address a customer's accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. The amendments in ASU 2018-15 align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license). Accordingly, the amendments in ASU 2018-15 require an entity (customer) in a hosting arrangement that is a service contract to follow the guidance in ASC 350-40 to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The amendments in ASU 2018-15 also require the entity to present the expense related to the capitalized implementation costs in the same line item in the statement of income as the fees associated with the hosting element (service) of the arrangement and classify payments for capitalized implementation costs in the statement of cash flows in the same manner as payments made for fees associated with the hosting element. The entity is also required to present the capitalized implementation costs in the statement of financial position in the same line item that a prepayment for the fees of the associated hosting arrangement would be presented. The amendments in ASU 2018-15 are effective for interim and annual periods beginning on or after December 15, 2019 with early adoption permitted in any interim period. The Company will adopt the amendments in ASU 2018-15 in the first quarter of 2020 and expects there will be no impact to its consolidated financial statements on adoption but does expect to begin capitalizing implementation costs incurred in cloud computing arrangements post-adoption.

## 2. 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 maker. 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.



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.



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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, material handling components and extruded raw material stock. 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. 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.

While no single customer accounted for over 10% of the Company's consolidated revenue in 2018, certain customers provided a significant portion of each business segment's 2018 revenue. The Electric segment has one customer that provided 11.2% of 2018 segment revenues. The Manufacturing segment has one customer that manufactures and sells recreational vehicles that provided 22.2% of 2018 segment revenues and one customer that manufactures and sells lawn and garden equipment that provided 11.2% of 2018 segment revenues. The Manufacturing segment's top five revenue-generating customers provided over 52% of 2018 segment revenues. The Plastics segment has two customers that together provided 39.1% of 2018 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 98.5% and 98.1% of operating revenues for the respective three-month periods ended September 30, 2019 and 2018, and 98.7% and 98.2% of operating revenues for the respective nine-month periods ended September 30, 2019 and 2018.

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three- and nine-month periods ended September 30, 2019 and 2018 and total assets by business segment as of September 30, 2019 and December 31, 2018 are presented in the following tables:

Operating Revenue

<i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2019	2018	2019	2018
<b>Electric Segment:</b>				
Retail Sales Revenue from Contracts with Customers	\$ 100,345	\$ 88,750	\$ 303,276	\$ 287,330
Changes in Accrued ARP Revenues	(921)	(317)	(1,601)	(2,757)
Total Retail Sales Revenue	99,424	88,433	301,675	284,573
Transmission Services Revenue	11,692	12,569	34,023	35,785
Wholesale Revenues – Company Generation	1,631	2,826	4,099	6,380
Other Revenues	1,626	1,614	4,929	5,394
Total Electric Segment Revenues	114,373	105,442	344,726	332,132
<b>Manufacturing Segment:</b>				
Metal Parts and Tooling	56,255	55,864	185,520	170,179
Plastic Products and Tooling	8,088	8,790	26,486	26,986
Other	1,379	2,373	5,034	6,678
Total Manufacturing Segment Revenues	65,722	67,027	217,040	203,843
Plastics Segment – Sale of PVC Pipe Products	48,566	55,203	142,100	159,332
Intersegment Eliminations	(9)	(10)	(39)	(31)
Total	\$ 228,652	\$ 227,662	\$ 703,827	\$ 695,276

Interest Charges

<i>(in thousands)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Electric	\$ 6,300	\$ 6,509	\$ 19,566	\$ 19,586
Manufacturing	561	555	1,791	1,664
Plastics	197	150	561	460
Corporate and Intersegment Eliminations	481	335	1,272	887
<b>Total</b>	<b>\$ 7,539</b>	<b>\$ 7,549</b>	<b>\$ 23,190</b>	<b>\$ 22,597</b>

Income Taxes

<i>(in thousands)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Electric	\$ 4,066	\$ 5,172	\$ 9,874	\$ 7,881
Manufacturing	285	799	2,888	3,040
Plastics	1,914	2,276	5,287	6,897
Corporate	(1,329)	(888)	(4,142)	(3,611)
<b>Total</b>	<b>\$ 4,936</b>	<b>\$ 7,359</b>	<b>\$ 13,907</b>	<b>\$ 14,207</b>

Net Income (Loss)

<i>(in thousands)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Electric	\$ 17,682	\$ 14,567	\$ 43,884	\$ 41,835
Manufacturing	3,155	3,022	11,987	10,769
Plastics	5,397	6,432	14,918	19,505
Corporate	(1,489)	(748)	(4,294)	(3,925)
<b>Total</b>	<b>\$ 24,745</b>	<b>\$ 23,273</b>	<b>\$ 66,495</b>	<b>\$ 68,184</b>

Identifiable Assets

<i>(in thousands)</i>	September 30, 2019	December 31, 2018
Electric	\$ 1,829,271	\$ 1,728,534
Manufacturing	206,835	187,556
Plastics	97,459	91,630
Corporate	46,626	44,797
<b>Total</b>	<b>\$ 2,180,191</b>	<b>\$ 2,052,517</b>

**3. Rate and Regulatory Matters**

Below are descriptions of OTP's major capital expenditure projects that have had, or are expected to 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 2019 and 2018.

Major Capital Expenditure Projects

Astoria Station—OTP is constructing this 245-megawatt (MW) simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota as part of its plan to reliably meet customers' electric needs, replace expiring capacity purchase agreements and prepare for the planned retirement of its Hoot Lake Plant in 2021. A final order granting an Advance Determination

of Prudence (ADP) for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations. On August 3, 2018 the SDPUC issued an order granting a site permit for Astoria

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Station. In a September 26, 2018 hearing the NDPSC established a GCR rider for future recovery of costs incurred for Astoria Station. On March 6, 2019 the SDPUC issued an order approving a settlement that allows a phase-in rider which includes recovery of Astoria Station costs. The interconnection agreement for Astoria Station was executed by MISO in December 2018 and accepted by the FERC in January 2019. Site preparation and excavating began in May 2019. As of September 30, 2019, OTP had capitalized approximately \$36.8 million in project costs and allowance for funds used during construction (AFUDC) associated with Astoria Station. OTP expects the project will cost approximately \$158 million.

Merricourt Wind Energy Center (Merricourt)—On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (collectively, EDF) to purchase and assume the development assets and certain specified liabilities associated with Merricourt, a 150-MW wind farm in southeastern North Dakota, for a purchase price of approximately \$34.7 million, subject to adjustments for interconnection costs. Also on November 16, 2016, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement (the TEPC Agreement) with EDF-RE US Development, LLC (EDF-USD) pursuant to which EDF-USD will develop, design, procure, construct, interconnect, test and commission the wind farm for consideration of approximately \$200.5 million, subject to certain adjustments, payable following the closing of the Purchase Agreement in installments in connection with certain project construction milestones. The agreements contain customary representations, warranties, covenants and indemnities for this type of transaction. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making Merricourt eligible for cost recovery under the Minnesota Renewable Resource Recovery rider, subject to qualifications and reporting obligations. The MPUC's final written order was issued on January 10, 2018. A final order for an ADP, subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on November 3, 2017. The phase-in rider approved by order of the SDPUC on March 6, 2019 includes recovery of Merricourt costs. The Merricourt generator interconnection agreement with MISO was approved by the FERC in April 2019.

In connection with action by the FERC, OTP and EDF agreed, in the First Amendment to the Purchase Agreement and the TEPC Agreement dated June 11, 2019, to change the purchase price to \$37.7 million and to make a related reallocation of responsibility for interconnection costs and liabilities. On July 16, 2019, OTP closed on the purchase of substantially all of the development assets and assumed certain specified liabilities from EDF related to Merricourt pursuant to the Purchase Agreement, as amended, for a purchase price of approximately \$37.7 million, subject to certain adjustments, and issued the notice to EDF-USD to begin construction in August 2019. As of September 30, 2019, OTP had capitalized approximately \$54.8 million in project costs and AFUDC associated with Merricourt. OTP expects the project will cost approximately \$258 million.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This 345-kilovolt transmission line, energized on February 6, 2019, extends 162 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., and the parties have equal ownership interest in the transmission line portion of the project. The 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 MISO 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 from the MVP. OTP capitalized costs of approximately \$106 million on this project, including assets that are 100% owned by OTP.

Recovery of OTP's major transmission investments is through the MISO Tariff and Minnesota, North Dakota and South Dakota base rates and 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 is 7.5056% and its allowed rate of return on equity (ROE) is 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, which occurred when final rates were implemented on November 1, 2017. Certain MISO expenses and revenues remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

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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 changes to the MNCIP financial incentive. The model included incentives for utilities 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 was also limited to 40% of 2017 MNCIP spending and 35% of 2018 spending and will be limited to 30% of 2019 spending. The new model reduces the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism. The Minnesota Department of Commerce (MNDOC) issued a decision on May 20, 2019 to extend all utilities 2017-2019 CIP plans one year, through 2020.

On April 1, 2019 OTP filed a request for approval of its 2018 energy savings, recovery of \$3.0 million in accrued financial incentives and recovery of 2018 program costs not included in base rates. On May 31, 2019 the MNDOC staff filed its comments with the MPUC on OTP's 2018 petition to update its MNCIP rider, recommending the MPUC approve OTP's petition with modifications. On June 24, 2019 OTP filed reply comments to the MNDOC staff recommendation reaffirming the \$3.0 million request and offered an alternative \$4.0 million financial incentive for the MPUC to consider. On October 24, 2019 the MPUC approved a \$3.0 million financial incentive for 2018.

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 MVPs 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 diverted 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 general rate case 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 MVPs 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, which granted review of the Minnesota Court of Appeals decision. Oral arguments were heard by the Minnesota Supreme Court on March 11, 2019.

On November 30, 2018 OTP filed its annual update and supplemental filing to the Minnesota TCR rider. In this filing two scenarios were submitted based on whether the Minnesota Supreme Court affirms the original decision by the Minnesota Court of Appeals to exclude the MVP projects from the TCR rider or overturns the Minnesota Court of Appeals decision and includes the two MVP projects in the TCR rider. Action by the Minnesota Supreme Court is expected in late 2019. In addition, on April 1, 2019, the MNDOC filed comments in OTP's TCR rider docket, opposing OTP's proposal for TCR rider recovery of these costs. The MPUC is not expected to act on the TCR rider until after the Minnesota Supreme Court has acted and additional briefing has occurred in the docket. The estimated amount credited to Minnesota customers through the TCR rider through September 30, 2019 is approximately \$2.6 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. Accordingly, in its 2018 annual update filing OTP requested, and the MPUC approved, setting the Minnesota ECR rider rate to zero effective December 1, 2018. The remaining under-recovered balance was charged on customer billings in March and April 2019.

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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 federal Production Tax Credits (PTCs) expiring on OTP's wind farms in 2017 and 2018. On June 21, 2019 OTP filed a request for approval of its annual update to the Minnesota RRA. This update requests recovery of the difference in PTCs in base rates and the actual PTCs generated, as well as recovery of Merricourt. On September 30, 2019 OTP filed a revised request which included changes related to Merricourt capitalized costs.

Fuel and Purchased Power Costs Recovery—In a December 2017 order, the MPUC adopted a program to implement certain procedural reforms to Minnesota utilities' automatic fuel adjustment clause (FAC) for fuel and purchased power cost recovery. With this order, the method of accounting for all Minnesota electric utilities changed to a monthly budgeted, forward-looking FAC with annual prudence review and true-up to actual allowed costs. On July 31, 2019 OTP submitted forecasted monthly fuel cost rates to the MPUC for the twelve-month period beginning January 1, 2020.

On implementation of the new mechanism, OTP will be required to accrue a liability and likely refund amounts of fuel and purchased power and related costs per kwh collected in excess of forecasted amounts per kwh submitted to the MPUC for setting rates for the upcoming year. OTP will continue to accrue revenue and a regulatory asset for fuel and purchased power costs incurred in excess of amounts recovered, that it expects to recover under the adjustment mechanism, unless and until recovery of those excess amounts are deemed not prudent and recovery is not granted through the true-up mechanism in a subsequent order by the MPUC. This mechanism could result in reductions in Electric segment operating income margins and could increase variability in consolidated net income in future periods if costs per kwh vary from forecasted costs per kwh and recovery of all or a portion of excess costs is denied by the MPUC.

## 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 requested \$13.1 million increase was net of reductions in North Dakota RRA, TCR and ECR rider revenues that would have resulted from a lower allowed rate of ROE 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 ROE of 10.3%. 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.

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 included \$4.8 million related to tax reform and \$1.2 million related to other updates.

In a September 26, 2018 hearing, the NDPSC approved an overall annual revenue increase of \$4.6 million (3.1%) and a ROE of 9.77% on a 52.5% equity capital structure. This compares with OTP's March 2018 adjusted annual revenue increase request of \$7.1 million (4.8%) and a requested ROE of 10.3%. The NDPSC's approval does not require any rate base adjustments from OTP's original request and establishes a GCR rider for future recovery of costs incurred for Astoria Station. The net revenue increase reflects a reduction in income tax recovery requirements related to the TCJA and decreases in rider revenue recovery requirements. Final rates were effective February 1, 2019, with refunds of excess revenues collected under interim rates applied to customers' April 2019 bills.

Renewable Resource Adjustment—OTP has a North Dakota RRA 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.

Effective in February 2019 with the implementation of general rates based on the results of OTP's 2017 general rate case, recovery of renewable resource costs previously being recovered through the North Dakota RRA rider transitioned to recovery in base rates.

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. Based on the order in the 2017 general rate case, only certain costs remained subject to refund or recovery through this rider: Southwest Power Pool (SPP) costs and MISO Schedule 26 and 26A revenues and expenses and costs related to rider projects still under construction in the test year used in the 2017 general rate case.



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OTP filed its annual update to the North Dakota TCR rider on August 30, 2019 seeking recovery of approximately \$5.7 million with a proposed effective date of January 1, 2020. The filing included seven new projects, updated costs associated with existing projects, details about the pending MISO ROE complaint, and details about SPP related expenses.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota. The ECR rider has provided for a return on investment at the level approved in OTP's preceding general rate case and for recovery of OTP's North Dakota share of environmental investments and costs approved for recovery under the rider. Prior to its 2017 general rate case reaching a final settlement and final rates going into effect on February 1, 2019, OTP's 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 were being recovered through the ECR rider. Effective February 1, 2019 these rate base investments are being recovered under general rates and the rider was zeroed out except for an overcollection balance that will be refunded to ratepayers. On October 22, 2019 the NDPSC approved OTP's request to decrease the ECR rate to zero effective November 1, 2019 and include the final tracker balance in OTP's next annual update to its RRA, which is expected to be filed on December 31, 2019.

Generation Cost Recovery Rider—On March 1, 2019 OTP filed a request with the NDPSC to establish an initial GCR rider rate for recovery of OTP's North Dakota jurisdictional share of the revenue requirements of its investment in Astoria Station. This request was approved by the NDPSC on May 15, 2019. The GCR rider went into effect on bills rendered after July 1, 2019.

## 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 went into effect October 18, 2018. The second step in the request was an additional 1.7% revenue increase to recover costs for Merricourt when the wind generation facility goes into service.

The SDPUC approved a partial settlement on March 1, 2019 on all issues of the rate case except ROE. The partial settlement included approval of a phase-in plan to provide for a return on amounts invested in Astoria Station and Merricourt, which addressed the second step of the request for increased rates in South Dakota. The partial settlement also includes a moratorium on filing another general rate case in South Dakota until the new generation projects have been in service for a year. The partial settlement also allowed OTP to retain the impact of lower tax rates related to the TCJA from January 1, 2018 through October 17, 2018 resulting in the reversal of an accrued refund liability and recognition of \$1.0 million in revenue in the first quarter of 2019. The SDPUC approved the ROE portion of the rate case on May 14, 2019. Pursuant to the May 30, 2019 order, OTP's allowed ROE was set at 8.75%, resulting in an annual revenue increase of approximately \$2.2 million prior to the approval of a June 28, 2019 stipulation agreement discussed below. Final rates went into effect August 1, 2019. An interim rate refund for the lower ROE going back to October 18, 2018 was applied to South Dakota customers' October 2019 bills.

On July 9, 2019 the SDPUC approved a stipulation agreement OTP entered into with SDPUC staff for the purpose of correcting a mistake in OTP's rate base in its 2018 general rate case docket. The revenue requirement stated in the SDPUC's final order dated May 30, 2019 understated the correct amount of OTP's electric transmission plant in service by approximately \$44 million. For South Dakota ratemaking purposes, the understatement resulted in an annual revenue requirement shortfall of approximately \$341,000. To address the shortfall, the parties agreed that OTP would file an update to its South Dakota TCR rider. OTP was authorized full recovery of the transmission rate base correction reflected in the TCR rider tracker beginning as of the first date of interim rates, October 18, 2018, with the TCR rider rate update going into effect on October 1, 2019. The stipulation agreement had the effect of increasing the non-fuel annual revenue increase in the general rate case to approximately \$2.6 million or 7.7%, which is 69% of the adjusted requested annual revenue increase of approximately \$3.7 million or 11.1%.

To ensure rates are appropriately set under the stipulation, the parties agreed to establish an earnings sharing mechanism to share with customers any weather-normalized earnings above the authorized ROE of 8.75%. OTP's annual weather-normalized earnings are reported each year by June 1 in its jurisdictional annual report, which will be used to determine the earnings level for purposes of calculating any refund. The earnings sharing mechanism requires that in the event OTP's annual weather-normalized earnings exceed the SDPUC's authorized ROE during any year until the ROE is reset in OTP's next general rate case, OTP will refund to customers 50% of any weather-normalized revenue that corresponds to the earnings in excess of its authorized ROE, up to a maximum of 9.50% ROE for a particular year. OTP will refund 100% of any earnings above 9.50% each year. In the event a refund is due under this provision, OTP will notify the SDPUC of the refund amount and plan for crediting customers within 30 days of filing its South Dakota jurisdictional annual report.

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**Transmission Cost Recovery Rider**—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP has a TCR rider in South Dakota. A supplemental filing to update the rider was made on January 29, 2018 to reflect updated costs and collections and incorporate the impact of the reduction in the federal corporate income tax rate under the TCJA. Effective October 18, 2018, with the implementation of interim rates under South Dakota general rate case proceedings, the TCR rate was decreased as a result of recovery of certain costs being shifted to recovery in interim rates and proposed for ongoing recoveries in final base rates at the end of the 2018 general rate case.

OTP made a supplemental filing for the South Dakota TCR rider on February 1, 2019. On February 20, 2019 the SDPUC approved the supplemental filing and rates effective March 1, 2019. Two new projects were approved for recovery under the rider: The Lake Norden area transmission upgrade project with a recovery date effective January 1, 2019 and the Big Stone South – Ellendale project with a recovery date effective January 2020.

OTP made a supplemental filing for the South Dakota TCR rider on September 5, 2019 to address the transmission rate base correction disclosed in the 2018 general rate case docket. On September 17, 2019 the SDPUC approved the supplemental filing and rates were effective October 1, 2019.

**Environmental Cost Recovery Rider**—OTP has an ECR rider in South Dakota. 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 South Dakota share of environmental investments and costs approved for recovery under the rider. Prior to interim rates going into effect on October 18, 2018 pending a final decision on OTP’s South Dakota general rate increase request, OTP’s South Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects were being recovered through the ECR rider. With the initiation of interim rates, recovery of the costs previously being recovered under the ECR rider was transitioned to recovery under interim rates and the South Dakota ECR rider rate was reset to provide a refund to customers while interim rates are in effect. The ending balance of the South Dakota ECR rider at the conclusion of interim rates was refunded to South Dakota customers along with their October 2019 interim rate refunds.

**Phase-In Rate Plan Rider**—On May 31, 2019 OTP petitioned the SDPUC for approval of its initial rate for the Phase-In Rate Plan Rider under the SDPUC’s authority granted in South Dakota. This rider filing is described in the most recent South Dakota general rate case settlement stipulation and approved by the SDPUC’s order in that rate case. The petition is OTP’s initial filing for the rider to recover, in OTP’s South Dakota jurisdiction, actual and forecasted costs for Astoria Station and Merricourt, and forecasted net benefits associated with additional load growth in the Lake Norden area.

OTP made a supplemental filing for the South Dakota Phase-In Rate Plan Rider on August 2, 2019. On August 21, 2019 the SDPUC approved the supplemental filing and the new rates were effective as of September 1, 2019.

**Revenues Recorded under Rate Riders**

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

Rate Rider ( <i>in thousands</i> )	Three Months Ended		Nine Months Ended	
	September 30, 2019	September 30, 2018	September 30, 2019	September 30, 2018
<b>Minnesota</b>				
Conservation Improvement Program Costs and Incentives	\$ 1,518	\$ 1,488	\$ 4,246	\$ 4,300
Renewable Resource Recovery	1,316	817	3,949	2,001
Transmission Cost Recovery	(284)	(1,196)	301	(1,683)
Environmental Cost Recovery	-	24	(1)	(25)
<b>North Dakota</b>				
Transmission Cost Recovery	908	1,922	3,554	5,149
Renewable Resource Adjustment	(20)	2,220	616	6,266
Generation Cost Recovery	137	-	607	-
Environmental Cost Recovery	(7)	1,823	556	5,474
<b>South Dakota</b>				
Transmission Cost Recovery	743	496	1,587	1,282
Conservation Improvement Program Costs and Incentives	100	238	440	589
Phase-In Rate Plan Recovery	(10)	-	(10)	-
Environmental Cost Recovery	(2)	545	(29)	1,580
<b>Total</b>	<b>\$ 4,399</b>	<b>\$ 8,377</b>	<b>\$ 15,816</b>	<b>\$ 24,933</b>



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Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2017 for the rate riders described above:

<b>Rate Rider</b>	<b>R - Request Date A - Approval Date</b>	<b>Effective Date Requested or Approved</b>	<b>Annual Revenue (\$000s)</b>	<b>Rate</b>
<b>Minnesota</b>				
Conservation Improvement Program				
2018 Incentive and Cost Recovery	A –October 24, 2019	December 1, 2019	\$ 11,926	\$0.00710/kwh
2017 Incentive and Cost Recovery	A –October 4, 2018	November 1, 2018	\$ 10,283	\$0.00600/kwh
2016 Incentive and Cost Recovery	A –September 15, 2017	October 1, 2017	\$ 9,868	\$0.00536/kwh
Transmission Cost Recovery				
2018 Annual Update–Scenario A	R –November 30, 2018	June 1, 2019	\$ 6,475	Various
–Scenario B			\$ 2,708	Various
2017 Rate Reset	A –October 30, 2017	November 1, 2017	\$ (3,311)	Various
Environmental Cost Recovery				
2018 Annual Update	A –November 29, 2018	December 1, 2018	\$ -	0% of base
2017 Rate Reset	A –October 30, 2017	November 1, 2017	\$ (1,943)	-0.935% of base
Renewable Resource Adjustment				
2019 Annual Update – Revised	R –September 30, 2019	November 1, 2019	\$ 12,506	\$0.00467/kwh
2018 Annual Update	A –August 29, 2018	November 1, 2018	\$ 5,886	\$0.00219/kwh
2017 Rate Reset	A –October 30, 2017	November 1, 2017	\$ 1,279	\$0.00049/kwh
<b>North Dakota</b>				
Renewable Resource Adjustment				
2019 Annual Update	A –May 1, 2019	June 1, 2019	\$ (235)	-0.224% of base
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
Transmission Cost Recovery				
2019 Annual Update	R –August 30, 2019	January 1, 2020	\$ 5,739	Various
2018 Supplemental Update	A –December 6, 2018	February 1, 2019	\$ 4,801	Various
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
Environmental Cost Recovery				
2019 Update	A –October 22, 2019	November 1, 2019	\$ -	0%of base
2018 Update	A –December 19, 2018	February 1, 2019	\$ (378)	-0.310%of base
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

-					
Generation Cost Recovery					
2019 Initial Request	A -May 15, 2019	July 1, 2019	\$	2,720	2.547% of base
<b>South Dakota</b>					
Transmission Cost Recovery					
2019 Rate Reset	A -September 17, 2019	October 1, 2019	\$	2,046	Various
2019 Annual Update	A -February 20, 2019	March 1, 2019	\$	1,638	Various
2018 Interim Rate Reset	A -October 18, 2018	October 18, 2018	\$	1,171	Various
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
Environmental Cost Recovery					
2018 Interim Rate Reset	A -October 18, 2018	October 18, 2018	\$	(189)	-\$0.00075/kwh
2017 Annual Update	A -October 13, 2017	November 1, 2017	\$	2,082	\$0.00483/kwh
Phase-In Rate Plan Recovery					
2019 Initial Request	A -August 21, 2019	September 1, 2019	\$	864	3.345% of base

## TCJA

The TCJA, passed in December 2017, reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. At the time of passage, OTP's electric rates had been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC each initiated dockets or proceedings to begin working with utilities to assess the impact of the lower rates on electric rates, and to develop regulatory strategies to incorporate the tax reduction into future electric rates, if warranted.

The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018. On August 9, 2018 the MPUC determined the impacts of the TCJA as calculated, including amortization of excess accumulated deferred income taxes, should be refunded and rates should be adjusted going forward to account for the impacts of the TCJA. On December 5, 2018 the MPUC issued its final order related to the TCJA docket directing OTP to return to ratepayers, in a one-time refund, the TCJA-related savings accrued prior to the refund effective date. OTP must amortize its protected excess accumulated deferred income taxes (ADIT) as early as U.S. Internal Revenue Service provisions allow and amortize its unprotected excess ADIT over ten years. OTP was instructed to use its 2017 year-end ADIT balance to calculate its excess ADIT balance. The order also directs OTP to use these savings to reduce customers' base rates prospectively, allocating the savings to customers in proportion to the size of each customer's bill, or to each customer class in proportion to the class's size. New rates reflecting the reduction in revenue requirements related to the TCJA tax rate reduction went into effect June 1, 2019. A one-time refund to Minnesota customers of \$11.5 million in excess of amounts billed from January 2018 through May 2019 occurred in August and September 2019.

As described above, OTP's recent general rate cases in North Dakota and South Dakota reflected the impact of the TCJA in interim rates. OTP accrued refund liabilities for the time periods during which revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurred under the lower federal tax rates in the TCJA. The North Dakota liability of \$0.8 million as of March 31, 2019 for amounts collected reflecting the higher tax rates under interim rates in effect in January and February 2018 was refunded with the interim rate refund in April 2019.

As of September 30, 2019, accrued refund liabilities related to the tax rate reduction were \$0.2 million for FERC jurisdictional rates. As of March 15, 2018, the FERC granted the request for waiver from a group of MISO transmission operators (including OTP) to revise inputs to their projected net revenue requirements for the 2018 rate year to reflect recent tax law changes.

## 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 suspension period, subject to ultimate approval by the FERC.

MVPs—MVPs are designed to enable the MISO 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 from the MVP.

ROE—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%. Several parties requested rehearing of the September 2016 order and the requests are pending FERC action.

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 went to 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

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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, 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 September 30, 2019.

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 (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. The motion is currently pending before the FERC.

On October 16, 2018 the FERC issued an order proposing a methodology for addressing the issues that were remanded to the FERC by the D.C. Circuit in April 2017. The FERC order established a paper hearing on how the methodology should apply to the proceedings pending before the FERC involving NETOs' ROE. In the order, the FERC selected a preliminary just and reasonable ROE for NETOs of 10.41%, exclusive of incentives, with a proposed cap on any pre-existing incentive-based total ROE at 13.08% and directed participants to submit supplemental briefs and additional written evidence regarding the proposed approaches to the Federal Power Act Section 206 inquiry and how to apply them to the NETO ROE complaints. On November 15, 2018, FERC issued an order establishing a paper hearing on whether and how a two-step ROE methodology developed for NETOs should apply to the ROE for MISO transmission owners. Initial briefs were due February 13, 2019 and reply briefs were due April 10, 2019. FERC is under no statutory timeline to act. OTP believes its estimated accrued MISO Tariff ROE refund liability of \$1.6 million as of September 30, 2019 related to the second MISO Tariff ROE complaint is appropriate.

On March 1, 2019 the FERC issued a Notice of Inquiry (NOI) seeking comment on whether, and if so how, it should modify its policies concerning the determination of the ROE used in designing jurisdictional rates charged by public utilities. For years, the FERC has utilized a particular two-step, analysis to establish ROEs for utilities and natural gas interstate pipelines. The NOI sought comments on whether it should develop ROEs using a different financial model. The NOI also sought comments, among other things, on the continued use of RTO Adders. Based on initial and reply comments to the NOI, which were filed during the summer of 2019, the FERC could issue a Notice of Proposed Rulemaking outlining a proposed change.

#### 4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

(in thousands)	September 30, 2019			Remaining Recovery/Refund Period (months)
	Current	Long-Term	Total	
<b>Regulatory Assets:</b>				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits <sup>1</sup>	\$ 6,355	\$ 113,657	\$ 120,012	see below
Accumulated ARO Accretion/Depreciation Adjustment <sup>1</sup>	-	7,571	7,571	asset lives
Conservation Improvement Program Costs and Incentives <sup>2</sup>	243	5,339	5,582	24
Minnesota Transmission Cost Recovery Rider Accrued Revenues <sup>2</sup>	2,856	-	2,856	12
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery <sup>1</sup>	-	1,525	1,525	asset lives
Deferred Marked-to-Market Losses <sup>1</sup>	972	186	1,158	15
Big Stone II Unrecovered Project Costs – Minnesota <sup>1</sup>	706	409	1,115	19
Debt Reacquisition Premiums <sup>1</sup>	203	598	801	156
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up <sup>1</sup>	60	711	771	27
South Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	418	-	418	12
Big Stone II Unrecovered Project Costs – South Dakota <sup>1</sup>	116	234	350	36
North Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	339	-	339	12
Minnesota SPP Transmission Cost Recovery Tracker <sup>1</sup>	-	270	270	see below
South Dakota Transmission Cost Recovery Rider Accrued Revenues <sup>2</sup>	193	-	193	5
Recoverable Fuel and Purchased Power Costs – South Dakota <sup>1</sup>	124	-	124	12
North Dakota Generation Cost Recovery Rider Accrued Revenues <sup>2</sup>	78	-	78	9
Deferred Lease Expenses <sup>1</sup>	-	51	51	42
Minnesota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	4	-	4	3
<b>Total Regulatory Assets</b>	<b>\$ 12,667</b>	<b>\$ 130,551</b>	<b>\$ 143,218</b>	
<b>Regulatory Liabilities:</b>				
Deferred Income Taxes	\$ -	\$ 141,337	\$ 141,337	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	-	96,981	96,981	asset lives
Refundable Fuel Clause Adjustment Revenues – Minnesota	3,836	-	3,836	3
North Dakota Renewable Resource Recovery Rider Accrued Refund	684	-	684	8
North Dakota Transmission Cost Recovery Rider Accrued Refund	601	-	601	2
North Dakota Environmental Cost Recovery Rider Accrued Refund	537	-	537	2
Revenue for Rate Case Expenses Subject to Refund – Minnesota	-	342	342	see below
Refundable Fuel Clause Adjustment Revenues – North Dakota	305	-	305	12

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	140	47	187	15
Minnesota Energy Intensive Trade Exposed Rider Accrued Refund	151	-	151	12
South Dakota Phase-In Rate Plan Rider Accrued Refund	39	-	39	12
Minnesota Renewable Resource Recovery Rider Accrued Refund	12	-	12	12
Other	6	74	80	171
<b>Total Regulatory Liabilities</b>	<b>\$ 6,311</b>	<b>\$ 238,781</b>	<b>\$ 245,092</b>	
<b>Net Regulatory Asset/(Liability) Position</b>	<b>\$ 6,356</b>	<b>\$ (108,230)</b>	<b>\$ (101,874)</b>	

<sup>1</sup>Costs subject to recovery without a rate of return.

<sup>2</sup>Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

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<i>(in thousands)</i>	December 31, 2018			Remaining Recovery/ Refund Period (months)
	Current	Long-Term	Total	
<b>Regulatory Assets:</b>				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits <sup>1</sup>	\$ 6,346	\$ 118,433	\$ 124,779	see below
Accumulated ARO Accretion/Depreciation Adjustment <sup>1</sup>	-	7,169	7,169	asset lives
Conservation Improvement Program Costs and Incentives <sup>2</sup>	5,995	3,285	9,280	21
Minnesota Transmission Cost Recovery Rider Accrued Revenues <sup>2</sup>	444	-	444	12
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery <sup>1</sup>	-	986	986	asset lives
Deferred Marked-to-Market Losses <sup>1</sup>	1,661	743	2,404	24
Big Stone II Unrecovered Project Costs – Minnesota <sup>1</sup>	681	947	1,628	28
Debt Reacquisition Premiums <sup>1</sup>	207	753	960	165
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up <sup>1</sup>	240	-	240	12
South Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	178	-	178	12
Big Stone II Unrecovered Project Costs – South Dakota <sup>1</sup>	100	342	442	53
North Dakota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	455	-	455	12
Minnesota SPP Transmission Cost Recovery Tracker <sup>1</sup>	-	176	176	see below
Minnesota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	121	-	121	12
Deferred Income Taxes <sup>1</sup>	-	2,423	2,423	asset lives
Minnesota Renewable Resource Recovery Rider Accrued Revenues <sup>2</sup>	452	-	452	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues <sup>1</sup>	328	-	328	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	17	-	17	12
<b>Total Regulatory Assets</b>	<b>\$ 17,225</b>	<b>\$ 135,257</b>	<b>\$ 152,482</b>	
<b>Regulatory Liabilities:</b>				
Deferred Income Taxes	\$ -	\$ 142,779	\$ 142,779	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	-	83,229	83,229	asset lives
Refundable Fuel Clause Adjustment Revenues	121	-	121	12
North Dakota Renewable Resource Recovery Rider Accrued Refund	177	-	177	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	60	-	60	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	-	166	166	see below
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	-	187	187	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	168	-	168	12
South Dakota Environmental Cost Recovery Rider Accrued Refund	207	-	207	12
Other	5	108	113	180
<b>Total Regulatory Liabilities</b>	<b>\$ 738</b>	<b>\$ 226,469</b>	<b>\$ 227,207</b>	
<b>Net Regulatory Asset/(Liability) Position</b>	<b>\$ 16,487</b>	<b>\$ (91,212)</b>	<b>\$ (74,725)</b>	

<sup>1</sup>Costs subject to recovery without a rate of return.

<sup>2</sup>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.

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

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

The Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that were recoverable from Minnesota customers as of the balance sheet date.

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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.

All Deferred Marked-to-Market Losses recorded as of the balance sheet date 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 156 months.

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.

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

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.

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

The Minnesota SPP Transmission Cost Recovery Tracker regulatory asset relates to costs incurred to serve Minnesota customers that are subject to recovery but that had not been billed to Minnesota customers as of the balance sheet date.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that were recoverable from South Dakota customers as of the balance sheet date.

North Dakota Generation Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investment in Astoria Station, a natural gas-fired combustion turbine generation facility under construction near Astoria, South Dakota. The balance represents amounts subject to recovery from North Dakota customers that had not been billed to North Dakota customers as of the balance sheet date.

Deferred Lease Expenses: Under ASC 842 accounting rules, for leases with scheduled escalating payments, rent expense is required to be recognized on a straight-line basis over the life of the lease based on the sum of those payments. Rate-regulated entities are generally only allowed to recover the amount of actual cash payments on leases and FERC accounting rules require that rent expense be recognized on the basis of cash payments. The balance in the deferred lease expense regulatory asset account represents operating lease right of use asset cumulative amortization and interest costs in excess of cumulative lease payments that are subject to recovery in future periods under regulatory accounting treatment as cash payments are rendered.

The Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that were recoverable from Minnesota customers as of the balance sheet date.

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

The Minnesota Renewable Resource Recovery Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that were recoverable from Minnesota customers as of the balance sheet date.

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 were subject to recovery from other Minnesota customers as of the balance sheet date.



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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 were recoverable from North Dakota customers as of the balance sheet date.

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

The North Dakota Renewable Resource Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that were refundable to North Dakota customers as of the balance sheet date.

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 were refundable to North Dakota customers as of the balance sheet date.

The North Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that were refundable to North Dakota customers as of the balance sheet date. Effective February 1, 2019 these rate base investments are being recovered under general rates and the rider was zeroed out except for an overcollection balance that is being refunded to North Dakota ratepayers through the rider.

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.

The Minnesota Energy Intensive Trade Exposed Rider Accrued Refund relates to over-collected amounts from Minnesota retail customers for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that were subject to refund to Minnesota customers as of the balance sheet date.

The South Dakota Phase-In Rate Plan Rider Accrued Refund relates to amounts collected for actual and forecasted costs for Astoria Station, Merricourt, and additional load growth that were refundable to South Dakota customers as of the balance sheet date.

The Minnesota Renewable Resource Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that were refundable to Minnesota customers as of the balance sheet date.

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 were refundable to South Dakota customers as of the balance sheet date.

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 were refundable to South Dakota customers as of the balance sheet date.

## 5. Common Shares and Earnings Per Share

### Shelf Registration

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.

### Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2018 through September 30, 2019:

Common Shares Outstanding, December 31, 2018	39,664,884
Issuances:	
Executive Stock Performance Awards (2016 shares earned)	102,198
Vesting of Restricted Stock Units	27,125
Restricted Stock Issued to Directors	15,700
Directors Deferred Compensation	594
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(55,224)
Common Shares Outstanding, September 30, 2019	39,755,277

### Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three- and nine-month periods ended September 30, 2019 and 2018. 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, 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 reconciliations.

	Three Months ended September 30,		Nine Months ended September 30,	
	2019	2018	2019	2018
Weighted Average Common Shares Outstanding – Basic	39,714,672	39,621,524	39,694,677	39,592,705
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	149,023	206,268	147,106	210,691
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	68,138	58,680	63,902	58,475
Nonvested Restricted Shares	13,107	14,761	14,896	17,712
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	1,799	2,332	1,999	2,522
Total Dilutive Shares	232,067	282,041	227,903	289,400
Weighted Average Common Shares Outstanding – Diluted	39,946,739	39,903,565	39,922,580	39,882,105

The effect of dilutive shares on earnings per share for the three- and nine-month periods ended September 30, 2019 and 2018, resulted in no differences greater than \$0.01 between basic and diluted earnings per share in any period.

## 6. Share-Based Payments

### Stock Incentive Awards

The following stock incentive awards were granted under the 2014 Stock Incentive Plan during the nine-month period ended September 30, 2019:

Award	Grant-Date	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
<b>Stock Performance Awards Granted:</b>				
Under Executive and Select Employee Agreements	February 13, 2019	47,800	\$ 42.875	December 31, 2021
Under Legacy Agreement	February 13, 2019	7,800	\$ 45.885	December 31, 2021
Restricted Stock Units Granted to Executive Officers	February 13, 2019	15,600	\$ 49.6225	25% per year through February 6, 2023
Restricted Stock Units Granted to Key Employees	April 8, 2019	13,270	\$ 44.45	100% on April 8, 2023
Restricted Stock Granted to Nonemployee Directors	April 8, 2019	15,700	\$ 49.73	33% per year through April 8, 2022

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration on retirement in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The grant-date fair value of each restricted stock unit granted to an executive officer was the average of the high and low market price per share on the date of grant. The grant-date fair value of each restricted stock unit granted to a key employee that is not an executive officer was the average of the high and low market price per share on the date of grant, discounted for the value of the dividend exclusion on those restricted stock units over the respective vesting periods.

Under the performance share awards the aggregate award for performance at target is 55,600 shares. For target performance the participants would earn an aggregate of 27,800 common shares for achieving the target set for the Company's 3-year average adjusted ROE. The participants would also earn an aggregate of 27,800 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, 2019 through December 31, 2021, 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, 2019 and the average closing price for the 20 trading days immediately preceding January 1, 2022. Actual payment may range from zero to 150% of the target amount, or up to 83,400 common shares. There are no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC Topic 718, *Compensation – Stock Compensation*, 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.

Under the 2019 Performance Award Agreements, payment and the amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to 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 vesting of these awards is accelerated and paid at target in the event of a change in control.

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 per share 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 earlier of the indicated vesting period for the respective awards or the date the grantee becomes eligible for retirement as defined in their award agreement.



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### Employee Stock Purchase Plan

In July 2019 the Company reinstated a 15% employee discount under its Employee Stock Purchase Plan (ESPP). The ESPP allows employees, through payroll withholding, to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of the six-month investment period. Under ASC Topic 718, *Compensation-Stock Compensation* (ASC 718), the Company is required to record compensation expense related to the 15% discount. The Company currently plans to issue common shares rather than purchase shares in the open market to meet the requirements of the ESPP.

As of September 30, 2019, the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately \$4.3 million (before income taxes) which will be amortized over a weighted-average period of 2.1 years.

Amounts of compensation expense recognized under the Company's stock-based payment programs for the three and nine-month periods ended September 30, 2019 and 2018 are presented in the table below:

<i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2019	2018	2019	2018
Stock Performance Awards Granted to Executive Officers	\$ 743	\$ 718	\$ 3,274	\$ 2,037
Restricted Stock Units Granted to Executive Officers	189	174	999	596
Restricted Stock Granted to Executive Officers	-	-	-	16
Restricted Stock Granted to Nonemployee Directors	203	165	572	496
Restricted Stock Units Granted to Key Employees	112	92	346	257
ESPP (15% discount)	54	-	54	-
Totals	\$ 1,301	\$ 1,149	\$ 5,245	\$ 3,402

## **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 September 30, 2019, 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 46.0% and 56.2% based on OTP's 2019 capital structure petition effective by order of the MPUC on July 19, 2019. As of September 30, 2019, OTP's equity-to-total-capitalization ratio including short-term debt was 52.2% and its net assets restricted from distribution totaled approximately \$497 million. Under the 2019 capital structure petition, total capitalization for OTP cannot exceed \$1,331,302,000.

## **8. Leases**

The Company adopted ASU 2016-02 and related updates (ASC Topic 842), which replaced previous lease accounting guidance, on January 1, 2019, using the modified retrospective method of adoption. As a result, prior periods have not been restated. ASC Topic 842 requires lessees to record assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Adoption of the standard resulted in the recognition of net lease assets and lease liabilities of \$20 million on January 1, 2019. The adoption of the new standard did not have a material effect on the Company's consolidated statements of income or cash flows. In addition, the adoption did not have a material impact on the Company's liquidity or the Company's covenant compliance under its current debt agreements.



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The Company elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows for the carry forward of lease classifications determined under the requirements of ASC Topic 840. The Company also elected the practical expedient related to land easements, allowing for the continuation of historical accounting treatment for land easements on existing agreements at OTP. In addition, the Company has elected the hindsight practical expedient to determine the reasonably certain lease term for leases in place at the time of adoption. The Company has elected the practical expedient to not separate nonlease components from lease components on real estate leases for the purpose of determining the classification and the value of lease assets and lease liabilities at the inception of a lease.

The Company enters into leases for coal rail cars, warehouse and office space, land and certain office, manufacturing and material handling equipment under varying terms and conditions. The lengths of the leases vary from less than one year to approximately ten years. If a lease contains an option to extend and there is reasonable certainty the option will be exercised, the option is considered in the lease term at inception. None of these leases met the criteria to be classified as financing leases. Of the operating leases in place on January 1, 2019, 50 were capitalized as right-of-use assets and the remainder were month-to-month leases with no long-term obligations.

The right-of-use asset operating leases in place at the time of adoption were capitalized on the basis of their remaining payment obligation balances, discounted to present value based on the Company's incremental borrowing rates (IBRs) appropriate to the leased asset and lease terms. The remaining payments for operating lease right-of-use assets are being charged to expense on a straight-line basis over the life of the lease.

For the Company's current lease obligations, no explicit interest rates were stated in the lease agreements and no implicit rates could be determined based on the terms of the agreements. Therefore, in all cases, the Company has applied a formula-based IBR appropriate to the individual company, type of lease and lease term.

The breakdown of right-of-use assets and lease liabilities as of September 30, 2019 by business segment is provided in the following table.

<i>(in thousands)</i>	Electric	Manufacturing	Plastics	Corporate	Total
<b>Right of Use Assets – Operating Leases:</b>					
Gross	\$ 3,557	\$ 19,967	\$ 666	\$ 769	\$ 24,959
Accumulated Amortization	(778)	(1,836)	(294)	(98)	(3,006)
Net of Accumulated Amortization	\$ 2,779	\$ 18,131	\$ 372	\$ 671	\$ 21,953
<b>Obligations:</b>					
Current Operating Lease Liabilities	\$ 985	\$ 2,541	\$ 326	\$ 154	\$ 4,006
Long-Term Operating Lease Liabilities	2,081	15,686	45	572	18,384
Total Lease Liabilities	\$ 3,066	\$ 18,227	\$ 371	\$ 726	\$ 22,390

The amounts of the Company's right-of-use operating lease obligations as of September 30, 2019 for each of the five years in the period 2019 through 2023 and in aggregate for the years beyond 2023 are presented in the following table.

<i>(in thousands)</i>	Right-of-Use Operating Leases		
	OTP	Nonelectric	Total
2019	\$ 275	\$ 1,029	\$ 1,304
2020	1,115	3,883	4,998
2021	1,100	3,619	4,719
2022	206	3,491	3,697
2023	196	3,203	3,399
Beyond 2023	448	7,979	8,427
Total Minimum Obligations	\$ 3,340	\$ 23,204	\$ 26,544
Interest Component of Obligations	(274)	(3,880)	(4,154)
Present Value of Minimum Obligations, September 30, 2019	\$ 3,066	\$ 19,324	\$ 22,390

The weighted-average remaining lease term for the Company's outstanding lease liabilities is 6.2 years and the weighted-average discount rate is 5.3%.

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A reconciliation of the Company's operating lease obligations on adoption of ASC Topic 842 on January 1, 2019 and its operating lease obligations on September 30, 2019 is provided in the table below.

<i>(in thousands)</i>	OTP	Nonelectric	Total
Operating Lease Obligations, January 1, 2019	\$ 3,609	\$ 16,760	\$ 20,369
Non-cash Acquisition of Right-of-Use Assets	177	5,115	5,292
Lease Modifications	-	(164)	(164)
Lease Obligation Payments	(845)	(3,086)	(3,931)
Interest Component of Lease Obligation Payment	125	699	824
Operating Lease Obligations, September 30, 2019	\$ 3,066	\$ 19,324	\$ 22,390

The lease modifications in the above table relate to reductions in future minimum lease obligations on several units of leased equipment at BTD.

OTP has obligations to make future operating lease payments primarily related to coal rail-car leases. OTP's rail-car lease payments are charged to fuel inventory and then expensed to production fuel – electric as a component of fuel cost when fuel is burned. OTP also leases office and operating equipment with lease payments charged to rent expense and reported in electric operation and maintenance expenses on the Company's consolidated statements of income. From time to time, OTP will lease construction equipment or land for lay-down yards for materials used on capital projects. These leases are generally short term in nature with the lease payments being charged to the related construction project and included in CWIP or plant in service after the project is completed and placed in service.

The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment. These payments are charged to rent expense accounts and reported in costs of goods sold or other nonelectric expenses, as appropriate, on the Company's consolidated statements of income.

The allocation of right-of-use asset and variable lease costs, including non-cash costs related to straight-line amortization of escalating lease payments, for the three- and nine-month periods ending September 30, 2019 is presented in the following table.

	Three Months Ended September 30, 2019			Nine Months Ended September 30, 2019		
	Operating Lease Cost	Variable Lease Cost	Total Lease Cost	Operating Lease Cost	Variable Lease Cost	Total Lease Cost
Plant in Service or CWIP	\$ 9	\$ -	\$ 9	\$ 29	\$ -	\$ 29
Inventory	244	-	244	707	-	707
Cost of Products Sold	963	65	1,028	2,942	137	3,079
Electric Operation and Maintenance Expenses	64	-	64	194	-	194
Other Nonelectric Expenses	51	(1)	50	156	-	156
Total	\$ 1,331	\$ 64	\$ 1,395	\$ 4,028	\$ 137	\$ 4,165

## 9. Commitments and Contingencies

### Construction and Other Purchase Commitments

At September 30, 2019 OTP had commitments under contracts, including its share of construction program commitments and other nonlease commitments, extending into 2021 of approximately \$138.9 million. At December 31, 2018 OTP had commitments under contracts, including its share of construction program commitments and other nonlease commitments, extending into 2021 of approximately \$64.5 million. The increase in commitments is mainly due to a \$77.5 million increase in commitments and contractual obligations in 2019 associated with the construction of OTP's Astoria Station natural gas-fired combustion turbine in eastern South Dakota. Spending commitments increased \$70.3 million for 2020 and \$9.7 million for 2021. Total 2019 unmet project commitments decreased \$5.7 million in 2019 with initiation of construction activities.

At December 31, 2018 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately \$5.0 million under a long-term supply agreement. On October 1, 2019 this resin supply agreement was replaced with a new six-year resin supply agreement that commences on January 1, 2020. Under the new resin supply agreement, there are no minimum purchase requirements, but T.O. Plastics is required to purchase all of a specified class of regrind resin delivered by the supplier at a set price per pound. Based on current forecasted production levels, T.O. Plastics anticipates the quantity of resin delivered under the supply agreement will not exceed its requirements over the six-year term of the supply agreement or exceed the market cost of

alternative sources of the resin. T.O. Plastics estimates it will pay the supplier approximately \$1.6 million annually under this agreement.

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### Electric Utility Capacity and Energy Requirements and Coal Purchase and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2042. OTP also 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 has an agreement with Peabody COALSALLES, LLC for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2020. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement. OTP has an all-requirements agreement with Navajo Transitional Energy Co. (NTEC) for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. There are no fixed minimum purchase requirements under this agreement. In October 2019, NTEC purchased the assets of Cloud Peak Energy Resources LLC, including its Spring Creek Mine in southeast Montana, through bankruptcy court. For a two-day period in October, operations at the Spring Creek Mine were suspended due to a disagreement between the Montana Department of Environmental Quality and the NTEC. Subsequent to the suspension of operations, the two parties agreed to allow the mine to operate for an additional seventy-five days while they work to resolve differences regarding the NTEC's waiver of sovereign immunity from the state's environmental laws.

### OTP Land Easements

OTP has commitments to make future payments for land easements not classified as leases, extending into 2034 of approximately \$10.4 million.

### Contingencies

OTP had a \$1.6 million refund liability on its balance sheet as of September 30, 2019 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. As discussed in note 3 in greater detail, OTP believes its estimated accrued refund liability is appropriate based on the current facts and circumstances and is awaiting further action by the FERC before determining if a change in this estimate will be needed.

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 potential ROE refund described above, the most significant contingencies that could impact the Company's consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed established reserve amounts, and litigation matters.

In 2015 the Environmental Protection Agency (EPA), acting under Section 111(d) of the Clean Air Act, issued the Clean Power Plan which required states to submit plans to limit carbon dioxide emissions from certain fossil fuel-fired power plants. The rule is not currently in effect as a result of a stay by the Supreme Court in 2016. In 2017, the EPA issued a Notice of Proposed Rulemaking to repeal the Clean Power Plan; comments were due in April 2018.

On August 21, 2018 the EPA proposed a replacement for the Clean Power Plan -- the Affordable Clean Energy (ACE) Rule. The final version of the ACE Rule, which went into effect on September 6, 2019, establishes guidelines for states to use in developing plans to address greenhouse gas emissions from existing coal-fired power plants and was finalized in conjunction with two related but separate and distinct rulemakings, which include repealing the Clean Power Plan and providing revisions to state implementation plan guidance. The ACE Rule establishes heat rate improvements, or efficiency improvements, as the best system of emissions reduction for carbon dioxide from existing coal-fired generation units. Heat rate is a measure of the amount of energy required to generate a unit of electricity. States will establish unit-specific standards of performance that reflect the emission limitation achievable through certain candidate heat-rate improvement technologies. The final ACE Rule does not include any final action regarding New Source Review. States have until mid-2022 to submit a state implementation plan to EPA for approval.

### 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 September 30, 2019, including those described above, will not be material.

## 10. Short-Term and Long-Term Borrowings

The following table presents the status of the Company's lines of credit as of September 30, 2019 and December 31, 2018:

<i>(in thousands)</i>	Line Limit	In Use on September 30, 2019	Restricted due to Outstanding Letters of Credit	Available on September 30, 2019	Available on December 31, 2018
Otter Tail Corporation Credit Agreement	\$ 130,000	\$ 35,837	\$ -	\$ 94,163	\$ 120,785
OTP Credit Agreement	170,000	73,160	16,561	80,279	160,316
<b>Total</b>	<b>\$ 300,000</b>	<b>\$ 108,997</b>	<b>\$ 16,561</b>	<b>\$ 174,442</b>	<b>\$ 281,101</b>

On October 31, 2019 both credit agreements were amended to extend the expiration dates by one year from October 31, 2023 to October 31, 2024 and the line limit on the Otter Tail Corporation Credit Agreement was increased to \$170 million. The amendments to the credit agreements are listed as Exhibits 4.2 and 4.3 to this report on Form 10-Q and are incorporated herein by reference.

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of September 30, 2019 and December 31, 2018:

<b>September 30, 2019</b> <i>(in thousands)</i>	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
<b>Short-Term Debt</b>	\$ 73,160	\$ 35,837	\$ 108,997
<b>Long-Term Debt:</b>			
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
PACE Note, 2.54%, due March 18, 2021		394	394
<b>Total</b>	<b>\$ 512,000</b>	<b>\$ 80,394</b>	<b>\$ 592,394</b>
Less: Current Maturities net of Unamortized Debt Issuance Costs	-	180	180
Unamortized Long-Term Debt Issuance Costs	1,830	369	2,199
<b>Total Long-Term Debt net of Unamortized Debt Issuance Costs</b>	<b>\$ 510,170</b>	<b>\$ 79,845</b>	<b>\$ 590,015</b>
<b>Total Short-Term and Long-Term Debt (with current maturities)</b>	<b>\$ 583,330</b>	<b>\$ 115,862</b>	<b>\$ 699,192</b>

<b>December 31, 2018</b> <i>(in thousands)</i>	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
<b>Short-Term Debt</b>	\$ 9,384	\$ 9,215	\$ 18,599
<b>Long-Term Debt:</b>			
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
PACE Note, 2.54%, due March 18, 2021		523	523
<b>Total</b>	<b>\$ 512,000</b>	<b>\$ 80,523</b>	<b>\$ 592,523</b>

Less: Current Maturities net of Unamortized Debt Issuance Costs	-	172	172
Unamortized Long-Term Debt Issuance Costs	1,942	407	2,349
Total Long-Term Debt net of Unamortized Debt Issuance Costs	\$ 510,058	\$ 79,944	\$ 590,002
Total Short-Term and Long-Term Debt (with current maturities)	\$ 519,442	\$ 89,331	\$ 608,773

## Long-Term Debt Issuances

### 2019 Note Purchase Agreement

On September 12, 2019, OTP entered into a Note Purchase Agreement (the 2019 Note Purchase Agreement) with the purchasers named therein (the Purchasers), pursuant to which OTP agreed to issue to the Purchasers, in a private placement transaction, \$175 million aggregate principal amount of OTP's senior unsecured notes consisting of (a) \$10,000,000 aggregate principal amount of its 3.07% Series 2019A Senior Unsecured Notes due October 10, 2029 (the Series 2019A Notes), (b) \$26,000,000 aggregate principal amount of its 3.52% Series 2019B Senior Unsecured Notes due October 10, 2039 (the Series 2019B Notes), (c) \$64,000,000 aggregate principal amount of its 3.82% Series 2019C Senior Unsecured Notes due October 10, 2049 (the Series 2019C Notes), (d) \$10,000,000 aggregate principal amount of its 3.22% Series 2020A Senior Unsecured Notes due February 25, 2030 (the Series 2020A Notes), (e) \$40,000,000 aggregate principal amount of its 3.22% Series 2020B Senior Unsecured Notes due August 20, 2030 (the Series 2020B Notes), (f) \$10,000,000 aggregate principal amount of its 3.62% Series 2020C Senior Unsecured Notes due February 25, 2040 (the Series 2020C Notes) and (g) \$15,000,000 aggregate principal amount of its 3.92% Series 2020D Senior Unsecured Notes due February 25, 2050 (the Series 2020D Notes); and together with the Series 2019A Notes, the Series 2019B Notes, the Series 2019C Notes, the Series 2020A Notes, the Series 2020B Notes and the Series 2020C Notes, (the Notes).

On October 10, 2019, OTP issued the Series 2019A Notes, Series 2019B Notes and Series 2019C Notes (the 2019 Notes) pursuant to the 2019 Note Purchase Agreement. OTP used a portion of the \$100 million proceeds from the issuance to repay \$69.9 million of existing indebtedness under the OTP Credit Agreement, primarily incurred to fund OTP capital expenditures, and intends to use the remainder of the proceeds to pay for additional capital expenditures and for OTP's general corporate purposes. The Series 2020A Notes, the Series 2020C Notes and the Series 2020D Notes are expected to be issued on February 25, 2020, and the Series 2020B Notes are expected to be issued on August 20, 2020, subject to the satisfaction of certain customary conditions to closing.

OTP may prepay all or any part of the 2019 Notes (in an amount not less than 10% of the aggregate principal amount of the 2019 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 2019 Note Purchase Agreement, any prepayment made by OTP of all of the (a) Series 2019A Notes then outstanding on or after April 10, 2029, (b) Series 2019B Notes then outstanding on or after April 10, 2039 or (c) Series 2019C Notes then outstanding on or after April 10, 2049 will be made without any make-whole amount. The 2019 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 2019 Note Purchase Agreement) of OTP.

The 2019 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 2019 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants. Specifically, OTP may not permit its Interest-bearing Debt (as defined in the 2019 Note Purchase Agreement) to exceed 60% of Total Capitalization (as defined in the 2019 Note Purchase Agreement), determined as of the end of each fiscal quarter. OTP is also restricted from allowing its Priority Indebtedness (as defined in the Note Purchase Agreement) to exceed 20% of Total Capitalization, determined as of the end of each fiscal quarter. The 2019 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 2019 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2019 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2019 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2019 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2019 Note Purchase Agreement. The 2019 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 credit agreement, provided that no default or event of default has occurred and is continuing.

The 2019 Note Purchase Agreement is listed as Exhibit 4.1 to this report on Form 10-Q and is incorporated herein by reference.

## 11. Pension Plan and Other Postretirement Benefits

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

<i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2019	2018	2019	2018
Service Cost—Benefit Earned During the Period	\$ 1,373	\$ 1,615	\$ 4,119	\$ 4,845
Interest Cost on Projected Benefit Obligation	3,603	3,363	10,809	10,089
Expected Return on Assets	(5,324)	(5,300)	(15,973)	(15,899)
Amortization of Prior-Service Cost:				
From Regulatory Asset	1	4	4	12
From Other Comprehensive Income <sup>1</sup>	2	-	6	-
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,163	1,784	3,488	5,351
From Other Comprehensive Income <sup>1</sup>	26	46	79	137
Net Periodic Pension Cost <sup>2</sup>	\$ 844	\$ 1,512	\$ 2,532	\$ 4,535

<sup>1</sup>Corporate cost included in nonservice cost components of postretirement benefits.

<sup>2</sup>Allocation of Costs:

Costs included in OTP capital expenditures	\$ 333	\$ 455	\$ 1,059	\$ 1,162
Service costs included in electric operation and maintenance expenses	1,007	1,119	2,961	3,561
Service costs included in other nonelectric expenses	33	41	99	121
Nonservice costs capitalized as regulatory assets	(128)	(29)	(408)	(74)
Nonservice costs included in nonservice cost components of postretirement benefits	(401)	(74)	(1,179)	(235)

**Cash flows**—The Company had no minimum funding requirement as of December 31, 2018 but made discretionary plan contributions of \$10 million in January 2019 and \$12.5 million in September 2019.

**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:

<i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2019	2018	2019	2018
Service Cost—Benefit Earned During the Period	\$ 104	\$ 100	\$ 313	\$ 300
Interest Cost on Projected Benefit Obligation	433	399	1,301	1,197
Amortization of Prior-Service Cost:				
From Regulatory Asset	2	4	4	12
From Other Comprehensive Income <sup>1</sup>	4	10	12	29
Amortization of Net Actuarial Loss:				
From Regulatory Asset	31	66	93	200
From Other Comprehensive Income <sup>1</sup>	87	166	262	496
Net Periodic Pension Cost <sup>2</sup>	\$ 661	\$ 745	\$ 1,985	\$ 2,234

<sup>1</sup>Amortization of prior service costs and net actuarial losses from other comprehensive income are included in nonservice cost components of postretirement benefits.

<sup>2</sup>Allocation of Costs:

Service costs included in electric operation and maintenance expenses	\$ 26	\$ 24	\$ 78	\$ 74
Service costs included in other nonelectric expenses	78	76	235	226
Nonservice costs included in nonservice cost components of	557	645	1,672	1,934



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

<i>(in thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2019	2018	2019	2018
Service Cost—Benefit Earned During the Period	\$ 321	\$ 382	\$ 964	\$ 1,145
Interest Cost on Projected Benefit Obligation	770	646	2,312	1,937
Amortization of Net Actuarial Loss:				
From Regulatory Asset	393	412	1,178	1,236
From Other Comprehensive Income <sup>1</sup>	10	11	29	32
Net Periodic Postretirement Benefit Cost <sup>2</sup>	\$ 1,494	\$ 1,451	\$ 4,483	\$ 4,350
Effect of Medicare Part D Subsidy	\$ (45)	\$ (37)	\$ (134)	\$ (110)

<sup>1</sup>Corporate cost included in nonservice cost components of postretirement benefits.

<sup>2</sup>Allocation of Costs:

Costs included in OTP capital expenditures	\$ 78	\$ 108	\$ 248	\$ 275
Service costs included in electric operation and maintenance expenses	235	264	693	841
Service costs included in other nonelectric expenses	8	10	23	29
Nonservice costs capitalized as regulatory assets	284	301	905	769
Nonservice costs included in nonservice cost components of postretirement benefits	889	768	2,614	2,436

## 12. Fair Value of Financial Instruments

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

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 September 30, 2019 and December 31, 2018 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.

<i>(in thousands)</i>	September 30, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	\$ 921	\$ 921	\$ 861	\$ 861
Short-Term Debt	(108,997)	(108,997)	(18,599)	(18,599)
Long-Term Debt including Current Maturities	(590,195)	(663,761)	(590,174)	(601,513)

## 13. Property, Plant and Equipment

No update required for interim reporting period.

#### 14. Income Tax Expense

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income before income taxes and income tax expense reported on the Company's consolidated statements of income for the three- and nine-month periods ended September 30, 2019 and 2018:

<i>(in thousands)</i>	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Income Before Income Taxes	\$ 29,681	\$ 30,632	\$ 80,402	\$ 82,391
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	\$ 7,717	\$ 7,964	\$ 20,905	\$ 21,422
Decreases in Tax from:				
Differences Reversing in Excess of Federal Rates	(933)	(838)	(2,690)	(2,932)
Research and Development Tax Credits	(612)	(202)	(987)	(562)
Excess Tax Deduction – Equity Method Stock Awards	-	(73)	(827)	(698)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(258)	(774)	(774)
Reconciliation and Prior Period Adjustments	(688)	2,109	(722)	2,028
Corporate Owned Life Insurance	(50)	(332)	(609)	(360)
Allowance for Funds Used During Construction – Equity	(239)	(138)	(419)	(416)
Federal Production Tax Credits	-	(707)	-	(2,757)
Other Comprehensive Income Deferred Tax Rate Adjustment	-	-	-	(531)
Other Items – Net	(1)	(166)	30	(213)
Income Tax Expense	\$ 4,936	\$ 7,359	\$ 13,907	\$ 14,207
Effective Income Tax Rate	16.6%	24.0%	17.3%	17.2%

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

<i>(in thousands)</i>	2019	2018
Balance on January 1	\$ 1,282	\$ 684
Increases Related to Tax Positions for Prior Years	37	6
Increases Related to Tax Positions for Current Year	153	113
Uncertain Positions Resolved During Year	(170)	(186)
Balance on September 30	\$ 1,302	\$ 617

The balance of unrecognized tax benefits as of September 30, 2019 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of September 30, 2019 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of September 30, 2019.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of September 30, 2019, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2016 for federal and North Dakota income taxes and prior to 2015 for Minnesota income taxes.

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

RESULTS OF OPERATIONS

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three and nine months ended September 30, 2019 and 2018 followed by a discussion of changes in our consolidated financial position during the nine months ended September 30, 2019 and our business outlook for the remainder of 2019.

Comparison of the Three Months Ended September 30, 2019 and 2018

Consolidated operating revenues were \$228.7 million for the three months ended September 30, 2019 compared with \$227.7 million for the three months ended September 30, 2018. Operating income was \$37.3 million for the three months ended September 30, 2019 compared with \$38.3 million for the three months ended September 30, 2018. The Company recorded diluted earnings per share of \$0.62 for the three months ended September 30, 2019 compared with \$0.58 for the three months ended September 30, 2018.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three-month periods ended September 30, 2019 and 2018 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:

<b>Intersegment Eliminations</b> <i>(in thousands)</i>	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018
Operating Revenues:		
Electric	\$ 9	\$ 10
Costs of Products Sold	5	4
Other Nonelectric Expenses	4	6

Electric

<i>(in thousands)</i>	Three Months Ended September 30,		Change	%
	2019	2018		Change
Retail Sales Revenues from Contracts with Customers	\$ 100,345	\$ 88,750	\$ 11,595	13.1
Changes in Accrued Revenues under Alternative Revenue Programs	(921)	(317)	(604)	(190.5)
Total Retail Sales Revenues	\$ 99,424	\$ 88,433	\$ 10,991	12.4
Transmission Services Revenues	11,692	12,569	(877)	(7.0)
Wholesale Revenues – Company Generation	1,631	2,826	(1,195)	(42.3)
Other Revenues	1,626	1,614	12	0.7
Total Operating Revenues	\$ 114,373	\$ 105,442	\$ 8,931	8.5
Production Fuel	18,331	17,129	1,202	7.0
Purchased Power – System Use	13,163	9,664	3,499	36.2
Electric Operation and Maintenance Expenses	35,869	33,897	1,972	5.8
Depreciation and Amortization	15,198	14,023	1,175	8.4
Property Taxes	3,965	4,094	(129)	(3.2)
Operating Income	\$ 27,847	\$ 26,635	\$ 1,212	4.6
<b>Electric Megawatt-hour (mwh) Sales</b>				
Retail mwh Sales	1,091,427	1,079,622	11,805	1.1
Wholesale mwh Sales – Company Generation	71,506	93,790	(22,284)	(23.8)
<b>Heating Degree Days</b>	42	107	(65)	(60.7)
<b>Cooling Degree Days</b>	288	339	(51)	(15.0)

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

	Three Months ended September 30,	
	2019	2018
Heating Degree Days	76.4%	209.8%
Cooling Degree Days	83.0%	95.8%

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kilowatt-hour (kwh) sales under actual weather conditions and expected retail kwh sales under normal weather conditions in the third quarters of 2019 and 2018 and between quarters:

	2019 vs Normal	2018 vs Normal	2019 vs 2018
Effect on Diluted Earnings Per Share	\$ (0.02)	\$ 0.00	\$ (0.02)

The \$11.0 million increase in retail sales revenue includes:

- A \$5.8 million increase in retail revenue related to the recovery of increases in fuel and purchased-power costs explained below.
- A \$2.8 million increase in average electric prices, mainly related to interim and final rate increases in South Dakota and to increased sales to customers in higher rate classifications.
- A \$1.7 million increase in transmission cost recovery revenues due to recent investments in transmission infrastructure and transmission costs not currently recovered in base rates.
- A \$1.2 million increase in retail revenue due to increased kwh sales, primarily to commercial customers, exclusive of the weather-related decrease in retail kwh sales.
- A \$0.5 million increase in Minnesota Renewable Rider revenues due to increased cost recovery requirements resulting from the expiration of federal Production Tax Credits (PTCs) in November 2018 on a company-owned wind farm.

partially offset by:

- A \$1.0 million decrease in retail revenues related to decreased consumption due to cooler weather in the third quarter of 2019 compared with the third quarter of 2018 reflected in a 15.0% decrease in cooling degree days between quarters.

Transmission services revenues decreased \$0.9 million due to a decrease in Midcontinent Independent System Operator, Inc. (MISO) tariff revenues associated with offsets received from independent generators to pay for transmission system upgrades made by Otter Tail Power Company (OTP) to facilitate the generators' access to the electric grid.

Wholesale electric revenues decreased \$1.2 million as cooler summer weather in the region resulted in decreased demand and lower prices for wholesale electricity. Wholesale prices per kwh sold were down 24.3%, making it uneconomical to generate and sell electricity from OTP's Hoot Lake Plant when the incremental cost of generation exceeded wholesale prices.

Production fuel costs increased \$1.2 million as a result of a 29.4% increase in the cost per kwh generated from our fuel-burning plants. The increased cost per kwh generated is mostly due to the absorption of Coyote Creek Mining Company's (CCMC's) fixed coal mining costs in Coyote Station's fuel inventory while no coal was being delivered to Coyote Station during its spring 2019 maintenance outage. The increased cost per kwh generated was partially offset by a 17.3% reduction in kwhs generated at all of OTP's fuel-burning plants.

The cost of purchased power to serve retail customers increased \$3.5 million (36.2%) due to a 105% increase in kwhs purchased as a result of reduced generation at both Hoot Lake Plant and Coyote Station. Hoot Lake Plant Unit 2 was offline for maintenance and repairs in July 2019. Hoot Lake Plant was also curtailed in August and September 2019 due to economic dispatch as market prices for electricity had declined below Hoot Lake Plant's incremental generating cost. Coyote Station generated fewer kwhs in July 2019 compared with July 2018 as it came back online in July 2019 after its extended maintenance outage. The price per kwh of purchased power decreased 33.5% in the third quarter of 2019 compared with the third quarter of 2018 due to a decrease in regional market prices for electricity driven by decreased demand due to cooler summer weather resulting in decreased air conditioning load in the Northern Plains region of the United States.

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Electric operating and maintenance expense increased \$2.0 million including:

- A \$2.7 million increase in expense related to the establishment of a \$2.7 million regulatory asset and credit to operating expense for deferred recovery of an income tax adjustment in the third quarter of 2018 related to 2017 Tax Cuts and Jobs Act (TCJA) guidance issued in that quarter. There was no similar expense reduction recorded in the third quarter of 2019. The income tax adjustment resulted from the August 2018 Internal Revenue Service (IRS) guidance clarifying changes related to the treatment of bonus depreciation rules for 2017, which affected 2017 deductions and corresponding reversals of excess deferred taxes in 2018. The adjustments related to the guidance resulted in a \$2.7 million increase in income tax expense in the third quarter of 2018, which is subject to recovery through future rate adjustments.
- A \$0.6 million increase in Hoot Lake Plant external services costs related to Unit 2 turbine repairs in the third quarter of 2019.
- A \$0.4 million increase in line clearance costs.

partially offset by:

- A \$1.0 million decrease in external services costs at Big Stone Plant mainly related to costs incurred during the plant's 2018 maintenance outage.
- A \$0.7 million decrease in labor-related benefit expenses.

Depreciation and amortization expense increased \$1.2 million mainly due to 2018 capital additions of transmission plant and OTP's new customer information system put in service in 2019.

<u>Manufacturing</u>					
Three Months Ended					
September 30,					
<i>(in thousands)</i>	2019	2018	Change	%	Change
Operating Revenues	\$ 65,722	\$ 67,027	\$ (1,305)		(1.9)
Cost of Products Sold	51,399	51,143	256		0.5
Operating Expenses	6,846	7,842	(996)		(12.7)
Depreciation and Amortization	3,505	3,716	(211)		(5.7)
Operating Income	\$ 3,972	\$ 4,326	\$ (354)		(8.2)

The \$1.3 million decrease in revenues in our Manufacturing segment includes the following:

- Revenues at BTD Manufacturing, Inc. (BTD) decreased \$0.6 million due to:
  - o A \$3.7 million increase in revenue from an increase in parts sales volume, including increased sales to manufacturers of recreational vehicles partially offset by decreased sales in energy and agricultural end markets.
  - o A \$0.7 million increase in tooling revenues.

more than offset by:

- o A \$3.8 million decrease in revenue primarily from lower material price changes passed through to customers.
- o A \$1.0 million reduction in revenues from scrap metal sales due to a 33.5% decrease in scrap metal prices and a 12.6% decrease in scrap volume.
- o A \$0.2 million decrease in other revenues.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products,

decreased \$0.7 million primarily due to a \$0.6 million decrease in sales of horticultural products, mostly due to a \$0.4 million shift in the timing of sales to the second quarter of 2019 that historically have occurred in the third quarter.

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

- Cost of products sold at BTD increased \$0.5 million mainly as a result of increased material costs on higher sales volume.
- Cost of products sold at T.O. Plastics decreased \$0.2 million due to the decrease in sales volume.

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The \$1.0 million decrease in operating expenses in our Manufacturing segment is mainly due to a \$1.4 million reduction in accrued short-term incentive costs between quarters at BTD, partially offset by increases of \$0.3 million in other operating expenses at BTD. Operating expenses at T.O. Plastics increased \$0.1 million between the quarters.

Depreciation and amortization expense at BTD decreased \$0.2 million as a result of certain assets reaching the ends of their depreciable lives.

<u>Plastics</u>					
Three Months Ended					
September 30,					
<i>(in thousands)</i>	2019	2018	Change	%	
				Change	Change
Operating Revenues	\$ 48,566	\$ 55,203	\$ (6,637)		(12.0)
Cost of Products Sold	37,353	42,222	(4,869)		(11.5)
Operating Expenses	2,872	3,260	(388)		(11.9)
Depreciation and Amortization	865	907	(42)		(4.6)
Operating Income	\$ 7,476	\$ 8,814	\$ (1,338)		(15.2)

Plastics segment revenues and operating income decreased \$6.6 million and \$1.3 million, respectively, due to an 8.9% decrease in pounds of polyvinyl chloride (PVC) pipe sold and a 3.5% decrease in PVC pipe prices. The quarter-over-quarter sales volume decrease relates to lower demand for product in the Midwest and West Coast states. Cost of products sold decreased \$4.9 million due to the reduced sales volume and a 2.9% decrease in the cost per pound of pipe sold. The decrease in pipe prices in excess of the decrease in costs per pound of pipe sold resulted in a 5.2% decrease in gross margin per pound of PVC pipe sold. Plastics segment operating expenses decreased \$0.4 million between the quarters mainly due to lower sales commissions and incentive compensation resulting from decreases in sales volume and operating income.

Corporate

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

Three Months Ended					
September 30,					
<i>(in thousands)</i>	2019	2018	Change	%	
				Change	Change
Operating Expenses	\$ 1,951	\$ 1,451	\$ 500		34.5
Depreciation and Amortization	89	62	27		43.5

Corporate operating expenses increased \$0.5 million mainly due to an increase in certain employee benefit costs.

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Income Tax Expense

The \$2.4 million decrease in income tax expense in the three months ended September 30, 2019 compared with the three months ended September 30, 2018 reflects a \$2.0 million adjustment to income tax expense at OTP in the third quarter of 2018 for the reversal of excess deferred taxes related to IRS guidance that clarified changes to bonus depreciation under the TCJA applicable to 2017 income taxes, a \$0.7 million reduction in tax expense due to 2019 reconciliations and prior periods adjustments and a \$0.4 million increase in research and development tax credits at BTD. These decreases were partially offset by a \$0.7 million decrease in federal PTCs resulting from the expiration of PTCs on OTP's Ashtabula wind farm in November 2018. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income before income taxes to income tax expense on our consolidated statements of income.

<i>(in thousands)</i>	Three Months Ended September 30,	
	2019	2018
Income Before Income Taxes	\$ 29,681	\$ 30,632
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	\$ 7,717	\$ 7,964
Decreases in Tax from:		
Differences Reversing in Excess of Federal Rates	(933)	(838)
Reconciliation and Prior Period Adjustments	(688)	2,109
Research and Development Tax Credits	(612)	(202)
Excess Tax Deduction – Equity Method Stock Awards	--	(73)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(258)
Allowance for Funds Used During Construction – Equity	(239)	(138)
Corporate Owned Life Insurance	(50)	(332)
Federal Production Tax Credits	--	(707)
Other Items – Net	(1)	(166)
Income Tax Expense	\$ 4,936	\$ 7,359
Effective Income Tax Rate	16.6%	24.0%

#### Comparison of the Nine Months Ended September 30, 2019 and 2018

Consolidated operating revenues were \$703.8 million for the nine months ended September 30, 2019 compared with \$695.3 million for the nine months ended September 30, 2018. Operating income was \$103.6 million for the nine months ended September 30, 2019 compared with \$106.0 million for the nine months ended September 30, 2018. The Company recorded diluted earnings per share of \$1.67 for the nine months ended September 30, 2019 compared with \$1.71 for the nine months ended September 30, 2018.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the nine-month periods ended September 30, 2019 and 2018 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:

<b>Intersegment Eliminations</b> <i>(in thousands)</i>	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Operating Revenues:		
Electric	\$ 36	\$ 31
Nonelectric	3	--
Costs of Products Sold	25	11
Other Nonelectric Expenses	14	20

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#### Electric

<i>(in thousands)</i>	Nine Months Ended September 30,		Change	%
	2019	2018		
Retail Sales Revenues from Contracts with	\$ 303,276	\$ 287,330	\$ 15,946	5.5

Customers							
Changes in Accrued Revenues under Alternative Revenue Programs							
		(1,601)	(2,757)	1,156	(41.9)		
Total Retail Sales Revenues	\$	301,675	\$	284,573	\$	17,102	6.0
Transmission Services Revenues		34,023		35,785		(1,762)	(4.9)
Wholesale Revenues – Company Generation		4,099		6,380		(2,281)	(35.8)
Other Revenues		4,929		5,394		(465)	(8.6)
Total Operating Revenues	\$	344,726	\$	332,132	\$	12,594	3.8
Production Fuel		45,547		51,723		(6,176)	(11.9)
Purchased Power – System Use		54,748		45,659		9,089	19.9
Other Operation and Maintenance Expenses		114,107		111,113		2,994	2.7
Depreciation and Amortization		44,765		41,924		2,841	6.8
Property Taxes		11,824		11,202		622	5.6
Operating Income	\$	73,735	\$	70,511	\$	3,224	4.6
<b>Electric mwh Sales</b>							
Retail mwh Sales		3,657,618		3,669,841		(12,223)	(0.3)
Wholesale mwh Sales – Company Generation		153,645		228,669		(75,024)	(32.8)
<b>Heating Degree Days</b>		4,692		4,373		319	7.3
<b>Cooling Degree Days</b>		392		567		(175)	(30.9)

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

	Nine Months ended September 30,	
	2019	2018
Heating Degree Days	118.0%	111.4%
Cooling Degree Days	86.0%	124.1%

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 first nine months of 2019 and 2018 and between the periods:

	2019 vs Normal	2018 vs Normal	2019 vs 2018
Effect on Diluted Earnings Per Share	\$ 0.06	\$ 0.06	\$ 0.00

The \$17.1 million increase in retail revenue includes:

- A \$5.7 million increase in transmission cost recovery rider revenues due to recent investments in transmission infrastructure and transmission costs not currently recovered in base rates.
- A \$5.5 million increase in retail revenue related to the recovery of increases in fuel and purchased power costs explained below.
- A \$2.8 million increase in average electric prices, mainly related to interim and final rate increases in South Dakota.
- A \$2.0 million increase in retail revenue in South Dakota due to the reversal of a tax refund provision in connection with OTP's 2018 South Dakota rate case settlement agreement.
- A \$1.9 million increase in Minnesota Renewable Rider revenues due to increased cost recovery requirements resulting from the expiration of federal PTCs in November 2018 on a company-owned wind farm.
- A \$0.6 million increase in revenue related to the establishment of a generation cost recovery rider in North Dakota in 2019 to provide for a return on funds invested in building Astoria Station during its construction phase.

partially offset by:

- A \$1.2 million decrease in retail revenue due to decreases in kwh sales to residential and industrial customers.

Transmission services revenues decreased \$1.8 million mainly due to a decrease in MISO tariff revenue associated with offsets received from independent generators to pay for transmission system upgrades made by OTP to facilitate the generators' access to the electric grid.

Wholesale electric revenues decreased \$2.3 million resulting from a 32.8% decrease in wholesales kwh sales due to fewer opportunities for wholesale sales as Coyote Station was offline during the second quarter of 2019 due to an extended maintenance outage and Hoot Lake Plant Unit 2 was offline for maintenance and repairs in June and July 2019. The decrease in revenues also resulted from decreased regional market demand in the third quarter of 2019 due to cooler summer weather, which also drove down wholesale electricity prices. The lower wholesale prices made it uneconomical to generate and sell electricity from OTP's Hoot Lake Plant when its incremental cost of generation exceeded wholesale prices.

Other electric revenues decreased \$0.5 million mainly due to a \$0.2 million reduction in revenue from sales of Renewable Energy Credits and a \$0.2 million reduction in late fees due to the suspension of late fee charges during the implementation of OTP's new customer information and billing system.

Production fuel costs decreased \$6.2 million mainly as a result of a 20.0% decrease in kwhs generated from our fuel-burning plants due to the maintenance outage at Coyote Station in the second quarter of 2019 and due to maintenance and repairs at Hoot Lake Plant in June and July of 2019. The decrease in fuel costs related to the decrease in generation was partially offset by a 10.1% increase in the cost of fuel per kwh generated at OTP's fuel-burning plants. The increased cost per kwh generated is mostly due to the absorption of CCMC's fixed coal mining costs in Coyote Station's fuel inventory while no coal was being delivered to Coyote Station during its spring 2019 maintenance outage.

The cost of purchased power to serve retail customers increased \$9.1 million (19.9%) due to a 37.6% increase in kwhs purchased as a result of needing to purchase replacement power during Coyote Station's maintenance outage and reduced availability of Hoot Lake Plant due to maintenance issues. The increased costs due to the increase in kwhs purchased was partially mitigated by a 12.9% decrease in the cost per kwh purchased resulting from lower wholesale energy prices.

Electric operating and maintenance expense increased \$3.0 million including:

- A \$2.7 million increase in expense related to the establishment of a regulatory asset and credit to operating expense for deferred recovery of an income tax adjustment in the third quarter of 2018 related to TCJA guidance issued in the quarter. There was no similar expense reduction recorded in the third quarter of 2019. The income tax adjustment is the result of August 2018 IRS guidance that clarified changes related to the treatment of bonus depreciation rules for 2017 that affected 2017 deductions and corresponding reversals of excess deferred taxes in 2018. The adjustments related to the guidance resulted in a \$2.7 million increase in income tax expense, which is subject to recovery through future rate adjustments.
- A \$2.7 million increase in external service and material and supplies expenses at Coyote Station related to its extended maintenance shutdown in the second quarter of 2019.
- A \$1.4 million increase in transmission services expenses mainly related to cost reductions and billing adjustments recorded in 2018.
- A \$0.9 million increase in external services and material and supplies expenses at Hoot Lake Plant related to maintenance and repairs performed during its shutdown in June and July of 2019.

partially offset by:

- A \$1.3 million decrease in external services expenses related to Big Stone Plant maintenance and repair costs incurred in September 2018 during the first month of a scheduled eight-week maintenance outage.
- A \$1.1 million decrease in labor costs and labor-related benefit expenses.
- A \$0.9 million decrease in line clearance costs.
- A \$0.5 million decrease in software-related expenses.
- A \$0.5 million decrease in storm repair costs.
- A \$0.4 million decrease in pollution control costs related to Coyote Station and Hoot Lake plant being off-line for extended periods of time in 2019 for scheduled and unplanned maintenance and repairs.

Depreciation expense increased \$2.8 million due to recent capital additions including the Big Stone South–Ellendale 345kV transmission line energized in February 2019, the new customer information system put in service in 2019 and other recent transmission plant upgrades. Property tax expense increased \$0.6 million due to capital additions in South Dakota and Minnesota.

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Manufacturing

<i>(in thousands)</i>	Nine Months Ended September 30,			% Change
	2019	2018	Change	
Operating Revenues	\$ 217,040	\$ 203,843	\$ 13,197	6.5
Cost of Products Sold	167,002	155,028	11,974	7.7
Operating Expenses	22,880	22,154	726	3.3
Depreciation and Amortization	10,606	11,330	(724)	(6.4)
Operating Income	\$ 16,552	\$ 15,331	\$ 1,221	8.0

The \$13.2 million increase in revenues in our Manufacturing segment includes the following:

- Revenues at BTD increased \$13.7 million, due to growth in parts revenue of \$16.2 million, including increased sales in recreational vehicle, construction, agricultural, and lawn and garden end markets, partially offset by reduced sales in energy end markets. Included in the parts revenue increase is the pass through of higher material costs of \$6.9 million, with the remaining increase due to \$8.7 million in higher sales volume and \$0.6 million in price increases unrelated to material cost increases passed through to customers. The increase in parts revenue was partially offset by a \$0.9 million decrease in tooling and other revenues and a \$1.6 million (24.6%) decrease in revenue from scrap metal sales due to a 23.2% decrease in scrap metal prices and a 1.9% decrease in scrap volume.
- Revenues at T.O. Plastics decreased \$0.5 million primarily due to a \$1.0 million decrease in industrial sales, mainly due to a customer bringing more production in house, offset by increases of \$0.3 million from sales of horticultural containers and \$0.2 million in sales of scrap material. The increase in horticultural sales is mainly due to growth of plug tray sales in certain horticultural markets.

The \$12.0 million increase in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased \$11.6 million including \$14.0 million in higher material costs, of which \$6.9 million was passed through to customers with the remaining \$7.1 million due to increased sales volume and cost increases not passed through to customers. The increase in material costs plus a \$2.8 million increase in overhead costs was partially offset by a \$5.2 million increase in recovery of tooling costs from customers.
- Cost of products sold at T.O. Plastics increased \$0.4 million mainly due to increased labor costs driven in part by increased production hours in response to higher sales volume and in part by wage increases.

The \$0.7 million increase in operating expenses in our Manufacturing segment includes increases of \$0.3 million at BTD and \$0.4 million at T.O. Plastics, including \$0.3 million in expenses associated with the partial collapse of a warehouse roof in the first quarter of 2019. Depreciation and amortization expense at BTD decreased \$0.6 million as a result of certain assets reaching the ends of their depreciable lives.

Plastics

<i>(in thousands)</i>	Nine Months Ended September 30,			% Change
	2019	2018	Change	
Operating Revenues	\$ 142,100	\$ 159,332	\$ (17,232)	(10.8)
Cost of Products Sold	110,348	120,674	(10,326)	(8.6)
Operating Expenses	8,486	9,136	(650)	(7.1)
Depreciation and Amortization	2,617	2,812	(195)	(6.9)
Operating Income	\$ 20,649	\$ 26,710	\$ (6,061)	(22.7)

Plastics segment revenues decreased \$17.2 million due to a 7.7% decrease in pounds of PVC pipe sold and a 3.4% decrease in PVC pipe prices. Because of record first quarter sales volume in 2018, the overall decrease in year-over-year sales volume was expected. Weather conditions across our sales territory also negatively impacted first quarter 2019 sales. Cost of products sold decreased \$10.3 million due to the decrease in sales volume and a 0.9% decrease in the cost per pound of pipe sold between periods. The decrease in pipe prices resulted in an 11.0% decrease in gross margin per pound of PVC pipe sold. Plastics segment operating expenses decreased \$0.7 million between periods mainly due to a decrease in incentive compensation related to the decrease in operating income.

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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.

<i>(in thousands)</i>	Nine Months Ended		Change	% Change
	2019	2018		
Operating Expenses	\$ 7,052	\$ 6,420	\$ 632	9.8
Depreciation and Amortization	241	150	91	60.7

Corporate operating expenses increased \$0.6 million mainly due to an increase in certain employee benefit costs.

Interest Charges

The \$0.6 million increase in interest charges for the nine months ended September 30, 2019 compared with the nine months ended September 30, 2018 is due to a \$49.7 million increase in average debt outstanding between the periods, the replacement of \$100 million of short-term debt bearing interest at 2.88% with long-term debt bearing interest at 4.07% in February 2018 and an increase in average short-term debt interest rates of approximately 1.1% between periods, partially offset by a \$0.2 million increase in capitalized interest at OTP between the periods.

Nonservice Cost Components of Postretirement Benefits

The \$1.0 million decrease in nonservice cost components of postretirement benefits in the nine months ended September 30, 2019 compared with the nine months ended September 30, 2018, is mostly due to a decrease in nonservice costs of the Company's pension plan, mainly actuarial loss amortization expenses, partially offset by interest costs increases on all of the Company's postretirement benefit plans.

Income Taxes

The \$0.3 million decreased income tax expense in the nine months ended September 30, 2019 compared with the nine months ended September 30, 2018 reflects a \$2.0 million adjustment to income tax expense at OTP in the third quarter of 2018 for the reversal of excess deferred taxes related to IRS guidance that clarified changes to bonus depreciation under the TCJA applicable to 2017 income taxes, a \$0.7 million reduction in tax expense due to 2019 reconciliations and prior periods adjustments and a \$0.4 million increase in research and development tax credits at BTD. These decreases were mostly offset by a \$2.8 million decrease in federal PTCs resulting from the expiration of PTCs on OTP's Ashtabula wind farm in November 2018. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income before income taxes to income tax expense on our consolidated statements of income for the nine-month periods ended September 30, 2019 and 2018:

<i>(in thousands)</i>	Nine Months Ended September 30,	
	2019	2018
Income Before Income Taxes	\$ 80,402	\$ 82,391
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	\$ 20,905	\$ 21,422
Decreases in Tax from:		
Differences Reversing in Excess of Federal Rates	(2,690)	(2,932)
Research and Development Tax Credits	(987)	(562)

Excess Tax Deduction – Equity Method Stock Awards	(827)	(698)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(774)	(774)
Reconciliation and Prior Period Adjustments	(722)	2,028
Corporate Owned Life Insurance	(609)	(360)
Allowance for Funds Used During Construction – Equity	(419)	(416)
Federal Production Tax Credits	--	(2,757)
Other Comprehensive Income Deferred Tax Rate Adjustment	--	(531)
Other Items – Net	30	(213)
Income Tax Expense	\$ 13,907	\$ 14,207
Effective Income Tax Rate	17.3%	17.2%

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**FINANCIAL POSITION**

The following table presents the status of our lines of credit as of September 30, 2019 and December 31, 2018:

<i>(in thousands)</i>	Line Limit	In Use on September 30, 2019	Restricted due to Outstanding Letters of Credit	Available on September 30, 2019	Available on December 31, 2018
Otter Tail Corporation Credit Agreement	\$ 130,000	\$ 35,837	\$ --	\$ 94,163	\$ 120,785
OTP Credit Agreement	170,000	73,160	16,561	80,279	160,316
Total	\$ 300,000	\$ 108,997	\$ 16,561	\$ 174,442	\$ 281,101

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 3, 2018 we filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 3, 2021. On May 3, 2018, we also filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares until May 3, 2021, under the Company's Automatic Dividend Reinvestment 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 Company will begin issuing common shares in the fourth quarter of 2019 to meet the requirements of the Plan rather than purchasing shares in the open market.

Equity and debt financing will be required in the period 2019 through 2023 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 7 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 5, 2019 our board of directors increased the quarterly dividend from \$0.335 to \$0.35 per common share.

Cash provided by operating activities was \$105.1 million for the nine months ended September 30, 2019 compared with \$100.9 million for the nine months ended September 30, 2018. The \$4.2 million increase in cash provided by operations between periods reflects \$3.8 million in noncash reductions in net income from increases in depreciation and stock-based compensation

expenses. A \$10.2 million increase in noncurrent liabilities and deferred credits was almost entirely offset by a \$7.5 million increase in deferred income taxes and other deferred debits and a \$2.5 million increase in discretionary pension fund contributions. Cash used for working capital decreased \$1.1 million, as a \$27.4 million increase in cash from reductions in inventory and collections of receivables was almost entirely offset by a \$26.3 million increase in cash used in the payment of current obligations.

Net cash used in investing activities was \$151.1 million for the nine months ended September 30, 2019 compared with \$75.9 million for the nine months ended September 30, 2018. The \$75.2 million increase in cash used for investing activities is primarily due to an increase in cash used for capital expenditures, mainly at OTP related to construction of the Merricourt Wind Energy Center (Merricourt) and Astoria Station projects and various transmission projects and upgrades.

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Net cash provided by financing activities was \$46.0 million in the nine months ended September 30, 2019 compared with \$40.5 million in cash used for financing activities in the nine months ended September 30, 2018. Financing activities in the first nine months of 2019 included proceeds of \$90.4 million from borrowings under the OTP and Otter Tail Corporation credit agreements which were used, together with cash flows from operations, to fund OTPs capital expenditures. The Company also paid \$41.8 million in common dividend payments in the first nine months of 2019.

Financing activities in the first nine months of 2018 included proceeds from the issuance of \$100 million in privately placed 4.07% Senior Unsecured Notes due February 7, 2048, which were used to pay down a portion of borrowings then outstanding under the OTP credit agreement. Additional borrowings under the OTP and Otter Tail Corporation credit agreements were used to fund a portion of capital expenditures in the first nine months of 2018. Common dividend payments of \$39.9 million in the first nine months of 2018 was the major item contributing to the \$40.5 million in net cash used in financing activities for the nine months ended September 30, 2018.

**CAPITAL REQUIREMENTS**

**2019-2023 Capital Expenditures**

Our consolidated capital expenditure plan for the 2019-2023 time period was revised from \$1.07 billion at year-end 2018 to \$1.11 billion in the second quarter of 2019. The increase is primarily driven by the need for additional wind and technology-related investments and transmission investments. Given the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 8.6% over the 2018 to 2023 timeframe.

The following table shows our 2018 capital expenditures and our currently anticipated 2019 through 2023 capital expenditures and electric utility average rate base.

<i>(in millions)</i>	2018	2019	2020	2021	2022	2023	Total
<b>Capital Expenditures:</b>							
<u>Electric Segment:</u>							
Renewables and Natural Gas Generation		\$ 125	\$ 264	\$ 15	\$ 82	\$ --	\$ 486
Transformative Technology and Infrastructure		2	7	18	47	54	128
Transmission <i>(includes replacements)</i>		43	42	21	19	17	142
Other		43	45	58	49	55	250
Total Electric Segment	\$ 87	\$ 213	\$ 358	\$ 112	\$ 197	\$ 126	\$ 1,006
Manufacturing and Plastics Segments	18	20	18	19	23	19	99
<b>Total Capital Expenditures</b>	<b>\$ 105</b>	<b>\$ 233</b>	<b>\$ 376</b>	<b>\$ 131</b>	<b>\$ 220</b>	<b>\$ 145</b>	<b>\$ 1,105</b>
<b>Total Electric Utility Rate Base</b>	<b>\$ 1,100</b>	<b>\$ 1,176</b>	<b>\$ 1,394</b>	<b>\$ 1,531</b>	<b>\$ 1,581</b>	<b>\$ 1,665</b>	

Execution on the anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2019 through 2023 timeframe.

As of September 30, 2019, OTP had capitalized approximately \$54.8 million in project costs and allowances for funds used during construction (AFUDC) associated with Merricourt. OTP expects Merricourt will cost approximately \$258 million and be completed in October 2020. As of September 30, 2019, OTP had capitalized approximately \$36.8 million in project costs and AFUDC

associated with Astoria Station. OTP expects Astoria Station will cost approximately \$158 million and will be completed prior to the planned retirement of Hoot Lake Plant in May 2021. For further details on these two projects see disclosures in Note 3 to our consolidated financial statements.

### **Contractual Obligations**

In the first nine months of 2019, OTP paid down most of its \$64.5 million in obligations for commitments under contracts in place on December 31, 2018 and increased its construction program and other nonlease commitments for the last three months of 2019 and the years 2020 and 2021 to approximately \$138.9 million as of September 30, 2019. This includes commitments related to the construction of Astoria Station of \$19.7 million for the remainder of 2019, \$92.5 million for 2020 and \$9.7 million for 2021.

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### **CAPITAL RESOURCES**

On May 3, 2018 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 3, 2021. On May 3, 2018 we also filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares under our Automatic Dividend Reinvestment 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 Company will begin issuing common shares in the fourth quarter of 2019 to meet the requirements of the Plan rather than purchasing shares in the open market.

### **Short-Term Debt**

The following table presents the status of our lines of credit as of September 30, 2019 and December 31, 2018:

<i>(in thousands)</i>	Line Limit	In Use on September 30, 2019	Restricted due to Outstanding Letters of Credit	Available on September 30, 2019	Available on December 31, 2018
Offer Tail Corporation Credit Agreement	\$ 130,000	\$ 35,837	\$ --	\$ 94,163	\$ 120,785
OTP Credit Agreement	170,000	73,160	16,561	80,279	160,316
<b>Total</b>	<b>\$ 300,000</b>	<b>\$ 108,997</b>	<b>\$ 16,561</b>	<b>\$ 174,442</b>	<b>\$ 281,101</b>

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the OTC Credit Agreement), which provided for an unsecured \$130 million revolving credit facility that could be increased subject to certain terms and conditions. On October 31, 2019 the OTC Credit Agreement was amended to extend its expiration date by one year from October 31, 2023 to October 31, 2024, and to increase the amount of the revolving credit facility to \$170 million. The amendment also provides this facility can be increased to \$290 million subject to certain terms and conditions. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the OTC Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on our senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTC Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The OTC Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The OTC Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the OTC Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the OTC Credit Agreement can reduce the amount available for borrowing under the line by up to \$40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured \$170 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2019 the OTP Credit Agreement was amended to extend its expiration date by one year from October 31, 2023 to October 31, 2024. OTP can draw on this credit facility to support the working

capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed \$50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Both the OTC Credit Agreement and the OTP Credit Agreement currently expire on October 31, 2024. Borrowings under these agreements currently use LIBOR as the base to determine the applicable interest rate. LIBOR is currently expected to be eliminated by January 1, 2022. Both agreements contain a provision to determine how interest rates will be established in the event a replacement for LIBOR has not been identified before the agreement expires. The process calls for the parties to jointly agree on an alternate rate of interest to LIBOR, such as the Secured Overnight Financing Rate, that gives due consideration to

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prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time. The parties will enter into amendments to these agreements to reflect any alternate rate of interest and other related changes to the agreements as may be applicable. If for any reason an agreement cannot be reached on an alternate rate of interest, then any borrowings under the agreements will be determined using the Prime Rate plus a margin based on the Company's and OTP's long-term debt ratings at the time of the borrowings. If the alternate rate of interest agreed to by the parties is less than zero, such rate shall be deemed to be zero for the purposes of the credit agreement.

### **Long-Term Debt**

#### **2019 Note Purchase Agreement**

On September 12, 2019, OTP entered into a Note Purchase Agreement (the 2019 Note Purchase Agreement) with the purchasers named therein (the Purchasers), pursuant to which OTP agreed to issue to the Purchasers, in a private placement transaction, \$175 million aggregate principal amount of OTP's senior unsecured notes consisting of (a) \$10,000,000 aggregate principal amount of its 3.07% Series 2019A Senior Unsecured Notes due October 10, 2029 (the Series 2019A Notes), (b) \$26,000,000 aggregate principal amount of its 3.52% Series 2019B Senior Unsecured Notes due October 10, 2039 (the Series 2019B Notes), (c) \$64,000,000 aggregate principal amount of its 3.82% Series 2019C Senior Unsecured Notes due October 10, 2049 (the Series 2019C Notes), (d) \$10,000,000 aggregate principal amount of its 3.22% Series 2020A Senior Unsecured Notes due February 25, 2030 (the Series 2020A Notes), (e) \$40,000,000 aggregate principal amount of its 3.22% Series 2020B Senior Unsecured Notes due August 20, 2030 (the Series 2020B Notes), (f) \$10,000,000 aggregate principal amount of its 3.62% Series 2020C Senior Unsecured Notes due February 25, 2040 (the Series 2020C Notes) and (g) \$15,000,000 aggregate principal amount of its 3.92% Series 2020D Senior Unsecured Notes due February 25, 2050 (the Series 2020D Notes); and together with the Series 2019A Notes, the Series 2019B Notes, the Series 2019C Notes, the Series 2020A Notes, the Series 2020B Notes and the Series 2020C Notes, (the Notes).

On October 10, 2019, OTP issued the Series 2019A Notes, Series 2019B Notes and Series 2019C Notes (the 2019 Notes) pursuant to the 2019 Note Purchase Agreement. OTP used a portion of the \$100 million proceeds from the issuance to repay \$69.9 million of existing indebtedness under the OTP Credit Agreement, primarily incurred to fund OTP capital expenditures, and intends to use the remainder of the proceeds to pay for additional capital expenditures and for OTP general corporate purposes. The Series 2020A Notes, the Series 2020C Notes and the Series 2020D Notes are expected to be issued on February 25, 2020, and the Series 2020B Notes are expected to be issued on August 20, 2020, subject to the satisfaction of certain customary conditions to closing.

OTP may prepay all or any part of the 2019 Notes (in an amount not less than 10% of the aggregate principal amount of the 2019 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 2019 Note Purchase Agreement, any prepayment made by OTP of all of the (a) Series 2019A Notes then outstanding on or after April 10, 2029, (b) Series 2019B Notes then outstanding on or after April 10, 2039 or (c) Series 2019C Notes then outstanding on or after April 10, 2049 will be made without any make-whole amount. The 2019 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 2019 Note Purchase Agreement) of OTP.

The 2019 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 2019 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants. Specifically, OTP may not permit its Interest-bearing Debt (as defined in the 2019 Note Purchase Agreement) to exceed 60% of Total Capitalization (as defined in the 2019 Note Purchase Agreement), determined as of the end of each fiscal quarter. OTP is also restricted from allowing its Priority Indebtedness (as defined in the Note Purchase Agreement) to exceed 20% of Total Capitalization, determined as of the end of each fiscal quarter. The 2019 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 2019 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2019 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2019 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2019 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2019 Note Purchase Agreement. The 2019 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 credit agreement, provided that no default or event of default has occurred and is continuing.

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### 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 2018 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 2018 Note Purchase Agreement, any prepayment made by OTP of all of the 2018 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 2018 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 as described below under the heading "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 (an 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.

### 2016 Note Purchase Agreement

On September 23, 2016 we entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which we agreed to issue to the purchasers, in a private placement transaction, \$80 million aggregate principal amount of our 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. Our obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by our Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining \$52,330,000 of our 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the \$50 million in funds borrowed in February 2016 under a Term Loan Agreement.

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

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and our Material Subsidiaries. These include restrictions on our and our Material Subsidiaries’ abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on our and our Material Subsidiaries’ shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading “Financial Covenants.” The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our or our Material Subsidiaries’ credit ratings.

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### 2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$60 million aggregate principal amount of OTP’s 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and \$90 million aggregate principal amount of OTP’s 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The notes were issued on February 27, 2014.

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

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

### 2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its \$122 million senior unsecured notes issued in three series consisting of \$30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; \$42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and \$50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007

(the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire its \$33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

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

#### Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of September 30, 2019.

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

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

- Under the OTC Credit Agreement and the 2016 Note Purchase Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of September 30, 2019, our Interest and Dividend Coverage Ratio calculated under the requirements of the OTC Credit Agreement and the 2016 Note Purchase Agreement was 4.28 to 1.00.
- Under the 2016 Note Purchase Agreement, we may not permit our Priority Indebtedness to exceed 10% of our Total Capitalization.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of September 30, 2019, OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.44 to 1.00.
- Under the 2013 Note Purchase Agreement, the 2018 Note Purchase Agreement, and the 2019 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement.

As of September 30, 2019, our ratio of Interest-bearing Debt to Total Capitalization was 0.48 to 1.00 on a consolidated basis and 0.48 to 1.00 for OTP. Neither Otter Tail Corporation nor OTP had any Priority Indebtedness outstanding as of September 30, 2019.

#### OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling \$19.3 million, but our line of credit borrowing limits are only restricted by \$16.6 million in outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or

for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

## 2019 BUSINESS OUTLOOK

We are narrowing our 2019 diluted earnings per share guidance range to \$2.10 to \$2.20 compared with our previously announced guidance in the range of \$2.10 to \$2.25. We expect capital expenditures for 2019 to be \$233 million compared with actual cash used for capital expenditures of \$105 million in 2018. Our planned expenditures for 2019 include \$79 million for the Merricourt Wind Energy Center and \$46 million for Astoria Station.

Segment components of our 2019 earnings per share guidance range compared with 2018 actual earnings and previously announced 2019 guidance are as follows:

Diluted Earnings Per Share	2018 EPS by Segment	2019 Guidance February 18, 2019		2019 Guidance May 6, 2019		2019 Guidance August 5, 2019		2019 Guidance November 4, 2019	
		Low	High	Low	High	Low	High	Low	High
		Electric	\$ 1.36	\$ 1.46	\$ 1.49	\$ 1.48	\$ 1.51	\$ 1.48	\$ 1.51
Manufacturing	\$ 0.32	\$ 0.37	\$ 0.41	\$ 0.35	\$ 0.39	\$ 0.33	\$ 0.37	\$ 0.31	\$ 0.33
Plastics	\$ 0.60	\$ 0.44	\$ 0.48	\$ 0.44	\$ 0.48	\$ 0.46	\$ 0.50	\$ 0.47	\$ 0.50
Corporate	\$ (0.22)	\$ (0.17)	\$ (0.13)	\$ (0.17)	\$ (0.13)	\$ (0.17)	\$ (0.13)	\$ (0.16)	\$ (0.13)
<b>Total</b>	<b>\$ 2.06</b>	<b>\$ 2.10</b>	<b>\$ 2.25</b>	<b>\$ 2.10</b>	<b>\$ 2.25</b>	<b>\$ 2.10</b>	<b>\$ 2.25</b>	<b>\$ 2.10</b>	<b>\$ 2.20</b>
<b>Return on Equity</b>	11.5%	11.5%	12.3%	11.5%	12.3%	11.5%	12.3%	11.5%	12.0%

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The following items contribute to our current 2019 earnings guidance.

- We expect 2019 Electric segment net income to be higher than 2018 segment net income based on:
  - An annual net revenue increase of approximately \$2.6 million from the full approval of our South Dakota rate case settlement on May 14, 2019. The settlement also allowed us to retain the impact of lower tax rates related to the TCJA from January 1, 2018 through October 17, 2018. This outcome favorably impacts 2019 earnings by approximately \$0.02 per share.
  - Increases in AFUDC for planned capital projects, including Merricourt and Astoria Station, and an increase in North Dakota Generation Cost Recovery rider revenue related to Astoria Station Both projects began construction in 2019.
  - Increased revenues from completion of the Big Stone South–Ellendale project and additional transmission investments related to our South Dakota Transmission Reliability project.
  - Decreased operating and maintenance expenses due to decreasing costs of pension, medical, workers compensation and retiree medical benefits. The decrease in pension costs is a result of an increase in the discount rate from 3.90% to 4.50%.
  - Expenses incurred in the fourth quarter of 2018 that are not expected to occur in the fourth quarter of 2019 consist of \$2.0 million related to the Big Stone Plant outage and the contribution to the Otter Tail Power Company Foundation of \$500,000.

partially offset by:

- Higher depreciation and property tax expense due to large capital projects being put into service.
- The extension of the planned outage at Coyote Station due to turbine rotor blade damage that was discovered in the early stages of the outage, and the unplanned maintenance outage at Hoot Lake Plant.
- We now expect 2019 net income from our Manufacturing segment to be in line with 2018. The change is based on:
  - Softness in certain end markets served by BTM due to concerns over a slowing economy and continued softness in

scrap metal revenues based on lower scrap metal prices.

- o A decrease in earnings from T.O. Plastics mainly due to first quarter volume softness and the expected impact on business operations of the partial collapse and replacement of a warehouse roof, which was damaged in March of 2019 during a winter storm.
- o Backlog for the manufacturing companies of approximately \$56 million for 2019 compared with \$62 million one year ago.
- We expect 2019 net income from the Plastics segment to be lower than 2018 based on lower expected operating margins in 2019. This is due to lower sales volumes and lower PVC pipe prices in 2019 compared with 2018.
- Corporate costs, net of tax, are expected to be lower in 2019 than in 2018. In 2018, we incurred expenses of \$2 million for a contribution to the Otter Tail Corporation Foundation and \$1.2 million for accruals related to certain tax matters. These expenses are not expected to occur during the remainder of 2019.

#### Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, interim rate refunds, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the board of directors. A discussion of critical accounting policies is included under the caption "Critical Accounting Policies Involving Significant Estimates" on pages 57 through 59 of our Annual Report on Form 10-K for the year ended December 31, 2018. There were no material changes in critical accounting policies or estimates during the nine months ended September 30, 2019.

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

In connection with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as "may", "will", "expect", "anticipate", "continue", "estimate", "project", "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act. These forward-looking statements involve risks and uncertainties. Actual results may differ materially from those contemplated by the forward-looking statements due to, among other factors, the risks and uncertainties described in the section entitled "Risk Factors" in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018, as well as the various factors described below:

- Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.
- Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase borrowing costs and pension plan and postretirement health care expenses.
- Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.
- The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations

and debt covenants and pay dividends to our shareholders could have an adverse effect on us.

- We rely on our information systems to conduct our business, and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period, our business could be harmed.
- Economic conditions could negatively impact our businesses.
- If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.
- Our plans to grow our businesses through capital projects, including infrastructure and new technology additions, or to grow or realign our businesses through acquisitions or dispositions may not be successful, which could result in poor financial performance.
- We may, from time to time, sell assets to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any assets sold and other potential liabilities. The sale of any of our businesses could expose us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.
- Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.
- We are subject to risks associated with energy markets.
- Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect our business, financial condition, results of operations and prospects.
- Four of our operating companies have single customers that provide a significant portion of the individual operating company's and the business segment's revenue. The loss of, or significant reduction in revenue from, any one of these customers would have a significant negative financial impact on the operating company and its business segment and could have a significant negative financial impact on us.
- We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.
- Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.
- Our electric operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.
- Our electric transmission and generation facilities could be vulnerable to cyber and physical attack that could impair our ability to provide electrical service to our customers or disrupt the U.S. bulk power system.

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- Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.
- Changes to regulation of generating plant emissions, including but not limited to carbon dioxide emissions and regional haze regulation under state implementation plans, could affect our operating costs and the costs of supplying electricity to our customers and the economic viability of continued operation of certain of our steam-powered electric plants.
- Competition from foreign and domestic manufacturers, the price and availability of raw materials, trade policy and tariffs affecting prices and markets for raw material and manufactured products, prices and supply of scrap or recyclable material and general economic conditions could affect the revenues and earnings of our manufacturing businesses.
- Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC

resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.

- We compete against many other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish the pipe companies' products from those of our competitors.
- Changes in PVC resin prices can negatively affect our plastics business.

### Item 3. Quantitative and Qualitative Disclosures about Market Risk

At September 30, 2019 we had exposure to market risk associated with interest rates because we had \$35.8 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.50% under the OTC Credit Agreement and OTP had \$73.2 million in short-term debt outstanding on September 30, 2019 subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of our remaining consolidated long-term debt outstanding on September 30, 2019 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

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

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

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

### Item 4. Controls and Procedures

Under the supervision and with the participation of company management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of September 30, 2019, the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2019.

During the fiscal quarter ended September 30, 2019, there were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

### Item 1. Legal Proceedings

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

threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 28 through 35 of our Annual Report on Form 10-K for the year ended December 31, 2018.

Item 6. Exhibits

- 4.1 [Note Purchase Agreement dated as of September 12, 2019 between Otter Tail Power Company and the Purchasers named therein \(incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on September 16, 2019\).](#)
- 4.2 [Seventh Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2019, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank \(incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on November 5, 2019\).](#)
- 4.3 [Seventh Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2019, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank \(incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation on November 5, 2019\).](#)
- 31.1 [Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)
- 31.2 [Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)
- 32.1 [Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.](#)
- 32.2 [Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.](#)
- 101.SCH Inline XBRL Taxonomy Extension Schema Document.
- 101.CAL Inline XBRL Taxonomy Extension Calculation Linkbase Document.
- 101.LAB Inline XBRL Taxonomy Extension Label Linkbase Document.
- 101.PRE Inline XBRL Taxonomy Extension Presentation Linkbase Document.
- 101.DEF Inline XBRL Taxonomy Extension Definition Linkbase Document.
- 104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

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SIGNATURES

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

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug

Kevin G. Moug  
Chief Financial Officer and Senior Vice President  
(Chief Financial Officer/Authorized Officer)

Dated: November 8, 2019