Otter Tail Corp
Form 10-Q
November 09, 2018

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2018

OR

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

For the transition period from to

Commission file number 0-53713

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

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

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

866-410-8780

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

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

Large accelerated filer Accelerated filer

Non-accelerated filer 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, 2018 – 39,664,884 Common Shares ($5 par value)

OTTER TAIL CORPORATION

INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. financial statements

Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands)	**September 30, 2018**	**December 31, 2017**
Assets		
Current Assets		
Cash and Cash Equivalents	$649	$16,216
Accounts Receivable:		
Trade—Net	96,095	68,466
Other	8,036	7,761
Inventories	94,615	88,034
Unbilled Receivables	16,855	22,427
Income Taxes Receivable	--	1,181
Regulatory Assets	16,552	22,551
Other	8,611	12,491
Total Current Assets	241,413	239,127
Investments	9,123	8,629
Other Assets	36,721	36,006
Goodwill	37,572	37,572
Other Intangibles—Net	12,746	13,765
Regulatory Assets	124,553	129,576
Plant		
Electric Plant in Service	2,000,313	1,981,018
Nonelectric Operations	225,620	216,937
Construction Work in Progress	183,397	141,067
Total Gross Plant	2,409,330	2,339,022
Less Accumulated Depreciation and Amortization	844,042	799,419
Net Plant	1,565,288	1,539,603

Total Assets	$2,027,416	$2,004,278

See accompanying condensed notes to consolidated financial statements.

Table of Contents

Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	**September 30, 2018**	**December 31, 2017**
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	$15,489	$112,371
Current Maturities of Long-Term Debt	169	186
Accounts Payable	91,033	84,185
Accrued Salaries and Wages	21,486	21,534
Accrued Federal and State Income Taxes	2,708	--
Other Accrued Taxes	15,269	16,808
Regulatory Liabilities	7,926	9,688
Other Accrued Liabilities	9,373	11,389
Liabilities of Discontinued Operations	--	492
Total Current Liabilities	163,453	256,653
Pensions Benefit Liability	89,139	109,708
Other Postretirement Benefits Liability	70,703	69,774
Other Noncurrent Liabilities	25,889	22,769
Commitments and Contingencies (note 8)		
Deferred Credits		
Deferred Income Taxes	108,699	100,501
Deferred Tax Credits	20,325	21,379
Regulatory Liabilities	231,594	232,893
Other	2,328	3,329
Total Deferred Credits	362,946	358,102
Capitalization		
Long-Term Debt—Net	589,984	490,380
Cumulative Preferred Shares – Authorized 1,500,000 Shares Without Par Value; Outstanding – None	--	--
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding – None	--	--

Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2018—39,664,884 Shares; 2017—39,557,491 Shares	198,324	197,787
Premium on Common Shares	343,210	343,450
Retained Earnings	189,575	161,286
Accumulated Other Comprehensive Loss	(5,807)	(5,631)
Total Common Equity	725,302	696,892
Total Capitalization	1,315,286	1,187,272
Total Liabilities and Equity	$2,027,416	$2,004,278

See accompanying condensed notes to consolidated financial statements.

Table of Contents

Otter Tail Corporation Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	**Three Months Ended September 30, 2018**	**2017**	**Nine Months Ended September 30, 2018**	**2017**
Operating Revenues				
Electric:				
Revenues from Contracts with Customers	$105,749	$102,923	$334,858	$325,360
Changes in Accrued Revenues under Alternative Revenue Programs	(317)	471	(2,757)	(1,192)
Total Electric Revenues	105,432	103,394	332,101	324,168
Product Sales under Contracts with Customers	122,230	113,063	363,175	318,492
Total Operating Revenues	227,662	216,457	695,276	642,660
Operating Expenses				
Production Fuel – Electric	17,129	16,096	51,723	44,955
Purchased Power – Electric	9,664	13,371	45,659	48,935
Electric Operation and Maintenance Expenses	33,897	35,469	111,113	109,494
Cost of Products Sold (depreciation included below)	93,361	86,230	275,691	245,520
Other Nonelectric Expenses	12,547	10,631	37,690	30,625
Depreciation and Amortization	18,708	17,927	56,216	53,689
Property Taxes – Electric	4,094	3,721	11,202	11,228
Total Operating Expenses	189,400	183,445	589,294	544,446
Operating Income	38,262	33,012	105,982	98,214
Interest Charges	7,549	7,393	22,597	22,382
Nonservice Cost Components of Postretirement Benefits	1,326	1,403	4,129	4,215
Other Income	1,245	592	3,135	1,697
Income Before Income Taxes – Continuing Operations	30,632	24,808	82,391	73,314
Income Tax Expense – Continuing Operations	7,359	7,035	14,207	19,295
Net Income from Continuing Operations	23,273	17,773	68,184	54,019
Discontinued Operations				
(Loss) Income – net of Income Tax (Savings) Expense of $0, ($25), $0 and $53 for the respective periods	--	(39)	--	78
Net Income	23,273	17,734	68,184	54,097
Average Number of Common Shares Outstanding – Basic	39,621,524	39,507,581	39,592,705	39,440,416
Average Number of Common Shares Outstanding – Diluted	39,903,565	39,795,366	39,882,105	39,712,862

Basic Earnings Per Common Share:				
Continuing Operations	$0.59	$0.45	$1.72	$1.37
Discontinued Operations	--	--	--	--
	$0.59	$0.45	$1.72	$1.37
Diluted Earnings Per Common Share:				
Continuing Operations	$0.58	$0.45	$1.71	$1.36
Discontinued Operations	--	--	--	--
	$0.58	$0.45	$1.71	$1.36
Dividends Declared Per Common Share	$0.335	$0.320	$1.005	$0.960

See accompanying condensed notes to consolidated financial statements.

4

Table of Contents

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

(in thousands)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Net Income	$23,273	$17,734	$68,184	$54,097
Other Comprehensive Income (Loss):				
Unrealized (Losses) Gains on Available-for-Sale Securities:				
Reversal of Previously Recognized Losses (Gains) Realized on Sale of Investments and Included in Other Income During Period	4	(1)	(106)	(2)
Unrealized (Losses) Gains Arising During Period	(14)	52	(93)	90
Income Tax Benefit (Expense)	2	(18)	42	(31)
Change in Unrealized (Losses) Gains on Available-for-Sale Securities – net-of-tax	(8)	33	(157)	57
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 10)	232	157	692	473
Income Tax Expense	(60)	(63)	(180)	(189)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	--	--	(531)	--
Pension and Postretirement Benefit Plans – net-of-tax	172	94	(19)	284
Total Other Comprehensive Income (Loss)	164	127	(176)	341
Total Comprehensive Income	$23,437	$17,861	$68,008	$54,438

See accompanying condensed notes to consolidated financial statements.

Table of Contents

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

(in thousands)	**Nine Months Ended September 30, 2018**	**2017**
Cash Flows from Operating Activities		
Net Income	$68,184	$54,097
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Income from Discontinued Operations	--	(78)
Depreciation and Amortization	56,216	53,689
Deferred Tax Credits	(1,054)	(1,102)
Deferred Income Taxes	7,529	15,680
Change in Deferred Debits and Other Assets	10,641	7,875
Discretionary Contribution to Pension Plan	(20,000)	--
Change in Noncurrent Liabilities and Deferred Credits	(191)	1,788
Allowance for Equity/Other Funds Used During Construction	(1,586)	(636)
Stock Compensation Expense—Equity Awards	3,402	2,765
Other—Net	(201)	99
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(27,804)	(21,122)
Change in Inventories	(6,581)	4,825
Change in Other Current Assets	3,827	3,079
Change in Payables and Other Current Liabilities	5,746	(5,153)
Change in Interest and Income Taxes Receivable/Payable	2,932	(1,595)
Net Cash Provided by Continuing Operations	101,060	114,211
Net Cash Used in Discontinued Operations	(200)	(134)
Net Cash Provided by Operating Activities	100,860	114,077
Cash Flows from Investing Activities		
Capital Expenditures	(74,489)	(94,549)
Net Proceeds from Disposal of Noncurrent Assets	1,879	2,456
Cash Used for Investments and Other Assets	(3,324)	(3,158)
Net Cash Used in Investing Activities	(75,934)	(95,251)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(7)	4,826
Net Short-Term (Repayments) Borrowings	(96,882)	60,754
Proceeds from Issuance of Common Stock	--	4,349
Common Stock Issuance Expenses	(108)	--
Payments for Retirement of Capital Stock	(3,012)	(1,799)
Proceeds from Issuance of Long-Term Debt	100,000	--

Short-Term and Long-Term Debt Issuance Expenses	(441)	--
Payments for Retirement of Long-Term Debt	(148)	(48,172)
Dividends Paid	(39,895)	(37,958)
Net Cash Used in Financing Activities	(40,493)	(18,000)
Net Change in Cash and Cash Equivalents	(15,567)	826
Cash and Cash Equivalents at Beginning of Period	16,216	--
Cash and Cash Equivalents at End of Period	$649	$826

See accompanying condensed notes to consolidated financial statements.

Table of Contents

OTTER TAIL CORPORATION

CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed notes thereto should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017. Because of seasonal and other factors, the earnings for the three- and nine-month periods ended September 30, 2018 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following condensed notes are numbered to correspond to numbers of the notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

1. Summary of Significant Accounting Policies

Revenue Recognition

In May 2014 the Financial Accounting Standards Board (FASB) issued a major update to the Accounting Standards Codification (ASC), Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). The Company adopted the updates in ASC 606 effective January 1, 2018 on a modified retrospective basis but did not record a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASC 606 had no material impact on the timing of revenue recognition for the Company or its subsidiaries. ASC 606 is a comprehensive, principles-based accounting standard which amended previous revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

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

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

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

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

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

Table of Contents

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

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

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

Manufacturing Segment Revenues—Companies in the Manufacturing segment, BTD Manufacturing, Inc. (BTD) and T.O. Plastics, Inc. (T.O. Plastics), earn revenue predominantly from the production and delivery of custom-made or standardized parts to customers across several industries. BTD also earns revenue from the production and sale of tools and dies to other manufacturers. For the production and delivery of standardized products and other products made to 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 and adjusts the revenue for volume rebate variable pricing considerations the company expects the customer will earn and for applicable early payment discounts the company expects the customer will take. For revenue recognized on products when shipped, the operating companies have no further obligation to provide services related to such 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. Billed amounts of revenue recognized are adjusted for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. For revenue recognized on shipped products, there is no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The Plastics segment has one customer for which it produces and stores a product made to the customer’s specifications and design under a build and hold agreement. For sales to this customer, the operating company recognizes revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. Ownership of the pipe transfers to the customer prior to delivery and the operating company is paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

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

Agreements Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The Company does not offset assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet.

Table of Contents

Fair Value Measurements

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

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

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

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

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

September 30, 2018 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$1,373		
Corporate Debt Securities – Held by Captive Insurance Company		$6,012	
Government-Backed and Government-Sponsored Enterprises’ Debt Securities – Held by Captive Insurance Company		1,527	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	776		
Total Assets	$2,149	$7,539	

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

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

Government-Backed and Government-Sponsored Enterprises' and Corporate Debt Securities Held by the Company's Captive Insurance Company – Fair values are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

Table of Contents

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, 2018 could be as high as $54.8 million, OTP's 35% share of unrecovered costs.

Inventories

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

(in thousands)	September 30, 2018	December 31, 2017
Finished Goods	$ 28,907	$ 26,605
Work in Process	19,124	14,222
Raw Material, Fuel and Supplies	46,584	47,207
Total Inventories	$ 94,615	$ 88,034

Goodwill and Other Intangible Assets

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

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

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

Table of Contents

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, 2018 and December 31, 2017:

September 30, 2018 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 9,843	$ 12,648	15 - 203
Other	154	56	98	23
Total	$ 22,645	$ 9,899	$ 12,746	

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

The amortization expense for these intangible assets was:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Amortization Expense – Intangible Assets	$329	$336	$1,019	$1,001

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

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

Supplemental Disclosures of Cash Flow Information

	As of September 30,	
(in thousands)	2018	2017
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$12,059	$17,940

New Accounting Standards Adopted

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

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

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

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

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

New Accounting Standards Pending Adoption

ASU 2016-02—In February 2016 the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses. The Company has determined areas where the amendments in ASU 2016-02 are applicable to its businesses and has evaluated transition options and determined the practical expedients it will elect on implementation. The Company will not apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019. Other than first-time recognition of these types of operating leases on the Company's consolidated balance sheet, the implementation is not expected to have a significant impact on the Company's consolidated financial statements.

Table of Contents

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

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

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

2. Segment Information

Segment Information

The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. The Company's businesses have been classified into three segments to be consistent with its business strategy and the reporting and review process used by the Company’s chief operating decision makers. These businesses sell products and provide services to customers primarily in the United States. The Company’s business structure currently includes the following three segments: Electric, Manufacturing and Plastics. The chart below indicates the companies included in each segment.

Table of Contents

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

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

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

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

No single customer accounted for over 10% of the Company's consolidated revenues in 2017. The Electric segment has one customer that provided 11.7% of 2017 Electric segment revenues. The Manufacturing segment has one customer that manufactures and sells recreational vehicles that provided 24.3% of 2017 Manufacturing segment revenues and one customer that manufactures and sells lawn and garden equipment that provided 12.0% of 2017 Manufacturing segment revenues. The Plastics segment has two customers that individually provided 20.6% and 17.8% of 2017 Plastics segment revenues. The loss of any one of these customers would have a significant negative impact on the financial position and results of operations of the respective business segment and the Company.

All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.1% and 97.9% of its operating revenues for the respective three-month periods ended September 30, 2018 and 2017, and 98.2% and 98.2% of its operating revenues for the respective nine-month periods ended September 30, 2018 and 2017.

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

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Electric Segment:				
Retail Sales Revenue from Contracts with Customers	$88,750	$88,482	$287,330	$281,615
Changes in Accrued ARP Revenues	(317)	471	(2,757)	(1,192)
Total Retail Sales Revenue	88,433	88,953	284,573	280,423
Wholesale Revenues – Company Generation	2,826	1,549	6,380	3,600
Other Revenues	14,183	12,897	41,179	40,163
Total Electric Segment Revenues	$105,442	$103,399	$332,132	$324,186
Manufacturing Segment:				
Metal Parts and Tooling	$55,864	$44,750	$170,179	$142,278
Plastic Products and Tooling	8,790	7,905	26,986	24,833
Other	2,373	1,700	6,678	4,965
Total Manufacturing Segment Revenues	$67,027	$54,355	$203,843	$172,076
Plastics Segment – Sale of PVC Pipe Products	$55,203	$58,708	$159,332	$146,416
Intersegment Eliminations	$(10)	$(5)	$(31)	$(18)
Total	$227,662	$216,457	$695,276	$642,660

Table of Contents

Interest Charges

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Electric	$6,509	$6,362	$19,586	$19,187
Manufacturing	555	555	1,664	1,662
Plastics	150	157	460	483
Corporate and Intersegment Eliminations	335	319	887	1,050
Total	$7,549	$7,393	$22,597	$22,382

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Electric	$5,172	$3,548	$7,881	$12,052
Manufacturing	799	676	3,040	3,304
Plastics	2,276	3,826	6,897	8,074
Corporate	(888)	(1,015)	(3,611)	(4,135)
Total	$7,359	$7,035	$14,207	$19,295

Net Income (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Electric	$14,567	$10,869	$41,835	$36,563
Manufacturing	3,022	1,608	10,769	6,735
Plastics	6,432	6,092	19,505	13,166
Corporate	(748)	(796)	(3,925)	(2,445)
Discontinued Operations	--	(39)	--	78
Total	$23,273	$17,734	$68,184	$54,097

Identifiable Assets

(in thousands)	September 30, 2018	December 31, 2017
Electric	$1,695,659	$1,690,224
Manufacturing	186,973	167,023
Plastics	100,981	87,230
Corporate	43,803	59,801
Total	$2,027,416	$2,004,278

3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2018 and 2017.

Table of Contents

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of September 30, 2018 were approximately $103.6 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of September 30, 2018 were approximately $72.4 million, which includes assets that are 100% owned by OTP.

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

Minnesota

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

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

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

<u>Minnesota Conservation Improvement Programs (MNCIP)</u>—OTP recovers conservation-related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC. On May 25, 2016 the MPUC adopted the Minnesota Department of Commerce's (MNDOC's) proposed changes to the MNCIP financial incentive. The model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. The financial incentive is also limited to 40% of 2017 MNCIP spending, 35% of 2018 spending and 30% of 2019 spending.

Table of Contents

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in a decrease in energy savings compared to 2016 program results of approximately 10%. OTP requested approval for recovery of its 2017 MNCIP program costs not included in base rates on March 30, 2018. The request included a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC. On June 13, 2018, in reply comments to a MNDOC recommendation for approval filed on May 30, 2018, OTP increased its request for a financial incentive to $2.9 million. OTP's MNCIP rate of Conservation Cost Recovery Adjustment (CCRA) for bills rendered on and after October 1, 2018 (or the first month following the order) was approved on October 4, 2018 with a variance and a compliance filing required. The final order in this docket was issued in October 2018, making November 1, 2018 the effective date for the new CCRA rate. The MPUC approved a financial incentive of $2.9 million subject to further review by the MPUC to ensure no previous decisions conflict with the decision, with $0.3 million at risk of subsequent refund.

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 diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment resulted in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision would vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to jurisdictionally allocate costs of the FERC MVP transmission projects in the TCR rider.

On June 11, 2018 the Minnesota Court of Appeals reversed the MPUC's order related to the inclusion of Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale 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 has determined to review the decision of the Minnesota Court of Appeals. A decision by the Minnesota Supreme Court is expected in second quarter 2019. OTP plans to file for an updated TCR rider rate, prior to the Minnesota Supreme Court decision, to include the portion of revenue subject to recovery arising from the MISO MVP investments and associated revenues. The amount credited to Minnesota customers through the TCR through September 30, 2018 and subject to recovery if the Minnesota Court of Appeals decision is upheld, is approximately $2.5 million.

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

Renewable Resource Adjustment—Effective November 1, 2017, with the implementation of final rates in Minnesota, new rates were put into effect for the Minnesota RRA rider to address recovery of revenue reductions for federal Production Tax Credits (PTCs) included in base rates that expired for one of OTP’s wind farms in 2017 and 2018. On August 29, 2018 the MPUC issued an order approving OTP’s request for an increase in the recoverable amount in its 2018 annual update to the RRA rider.

North Dakota

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

Table of Contents

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 Generation Cost Recovery rider for future recovery of funds to be invested in the planned Astoria natural gas-fired generating facility. On September 28, 2018 the NDPSC issued its Order on Settlement. 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 will be effective January 1, 2019, with refunds of excess revenues collected under interim rates applied to customers' March 2019 bills. OTP has accrued an interim rate refund of $2.3 million as of September 30, 2018 for amounts billed under interim rates in excess of amounts OTP is entitled to under the approved revenue increase.

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

Renewable Resource Adjustment—OTP has a North Dakota 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. Based on the Order on Settlement in the general rate case, this rider will be zeroed out at the implementation of final rates, except for any under or over collections existing at the time of roll-in. Future revenue requirement increases resulting from the expiration of production tax credits will be subject to recovery through North Dakota RRA rider updates.

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 on Settlement in the general rate case, only certain costs will remain subject to refund or recovery through this rider: Southwest Power Pool 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 rate case. This rider will continue to be updated annually for new projects and updated costs for existing projects and associated recoverable expenses.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxic Standards (MATS) projects. The ECR rider provided for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs. Based on the Order on Settlement in the general rate case, this rider will be zeroed out at the implementation of final rates, except for any under or over collections existing at the time of roll-in.

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 full effects of the TCJA on South Dakota revenue requirements will be addressed in the rate case and incorporated into final rates at the conclusion of that case. The second step in the request is an additional 1.7% increase to recover costs for the proposed Merricourt wind generation facility when the facility goes into service.

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

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities and will continue to be used for the recovery or refund of amounts not included in interim or base rates.

Table of Contents

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and will continue to be used for the recovery or refund of amounts not included in interim or base rates.

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

Rate Rider Updates

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

Rate Rider	**R - Request Date** **A - Approval Date**	**Effective Date Requested or Approved**	**Annual Revenue *($000s)***	**Rate**
Minnesota				
Conservation Improvement Program				
2017 Incentive and Cost Recovery	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
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	$ 8,590	$0.00275/kwh
Transmission Cost Recovery				
2017 Rate Reset[1]	A – October 30, 2017	November 1, 2017	$ (3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ 4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$ 7,203	Various
Environmental Cost Recovery				
2018 Annual Update	R – July 3, 2018	December 1, 2018	$ --	0% of base
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$ (1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ 11,884	6.927% of base
Renewable Resource Adjustment				
2018 Annual Update	A – August 29, 2018	November 1, 2018	$ 5,886	$.00244/kwh
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$ 1,279	$.00049/kwh
North Dakota				
Renewable Resource Adjustment				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	$ 9,650	7.493% of base
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$ 9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	$ 9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	$ 9,262	7.573% of base

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

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

Table of Contents

Revenues Recorded under Rate Riders

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
Rate Rider *(in thousands)*	2018	2017	2018	2017
Minnesota				
Conservation Improvement Program Costs and Incentives	$1,488	$1,806	$4,300	$4,215
Renewable Resource Recovery	817	--	2,001	--
Environmental Cost Recovery	24	1,669	(25)	7,305
Transmission Cost Recovery	(1,196)	(594)	(1,683)	2,849
North Dakota				
Renewable Resource Adjustment	2,220	2,213	6,266	5,822
Environmental Cost Recovery	1,823	2,396	5,474	7,272
Transmission Cost Recovery	1,922	2,410	5,149	6,305
South Dakota				
Environmental Cost Recovery	545	613	1,580	1,755
Transmission Cost Recovery	496	596	1,282	1,324
Conservation Improvement Program Costs and Incentives	238	104	589	520
Total	$8,377	$11,213	$24,933	$37,367

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Until recently, OTP’s rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC all initiated dockets or proceedings to assess the impact to electric rates from the lower income tax rates under the TCJA and to develop regulatory strategies to incorporate the tax change into future rates, if warranted.

The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018. 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. No order has been issued and the details and timing of implementation currently are not known.

The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected after December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA.

As described above, OTP's current general rate cases in North Dakota and South Dakota reflect the impact of the TCJA. OTP has accrued refund liabilities for revenues collected under rates set to recover higher levels of federal income taxes than OTP is currently incurring under the lower federal tax rates in the TCJA. As of September 30, 2018, accrued refund liabilities related to the tax rate reduction were $6.0 million in Minnesota, $0.8 million in North Dakota for amounts collected under interim rates in effect in January and February 2018, and $1.1 million in South Dakota.

FERC

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

MVPs—MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit.

Table of Contents

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

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

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

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. Initial briefs are due 60 days from the date of the order with responses to those initial briefs due 30 days later.

OTP believes its estimated accrued MISO Tariff ROE refund liability of $1.6 million as of September 30, 2018 related to the second MISO tariff ROE complaint is appropriate, based on the information discussed above.

Table of Contents

4. Regulatory Assets and Liabilities

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

	September 30, 2018			Remaining Recovery/ Refund Period
(in thousands)	Current	Long-Term	Total	(months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$9,090	$ 105,675	$ 114,765	see below
Conservation Improvement Program Costs and Incentives[2]	2,799	4,722	7,521	24
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	7,038	7,038	asset lives
Deferred Marked-to-Market Losses[1]	2,262	1,158	3,420	27
Unrecovered Tax Adjustment to Deferred Income Tax Asset[1]	--	2,739	2,739	see below
Big Stone II Unrecovered Project Costs – Minnesota[1]	673	1,123	1,796	31
Debt Reacquisition Premiums[1]	218	805	1,023	168
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery[1]	--	695	695	asset lives
Minnesota Renewable Resource Recovery Rider Accrued Revenues[2]	475	--	475	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	367	467	56
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	422	--	422	7
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	333	--	333	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	180	60	240	15
Minnesota Southwest Power Pool Transmission Cost Recovery Tracker[1]	--	131	131	see below
Deferred Income Taxes[1]	--	40	40	asset lives
Total Regulatory Assets	$16,552	$ 124,553	$ 141,105	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$ 148,103	$ 148,103	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,123	83,123	

				asset lives
Refundable Fuel Clause Adjustment Revenues	6,632	--	6,632	12
North Dakota Renewable Resource Recovery Rider Accrued Refund	301	--	301	6
South Dakota Environmental Cost Recovery Rider Accrued Refund	266	--	266	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	221	--	221	1
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	19	182	201	15
South Dakota Transmission Cost Recovery Rider Accrued Refund	181	--	181	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	156	--	156	15
North Dakota Environmental Cost Recovery Rider Accrued Refund	117	--	117	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	107	107	see below
Other	6	79	85	183
North Dakota Transmission Cost Recovery Rider Accrued Refund	27	--	27	12
Total Regulatory Liabilities	$7,926	$231,594	$239,520	
Net Regulatory Asset/(Liability) Position	$8,626	$(107,041)	$(98,415)	

[1]*Costs subject to recovery excluding a rate of return.*

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

22

Table of Contents

(in thousands)	December 31, 2017 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$9,090	$112,487	$121,577	see below
Conservation Improvement Program Costs and Incentives[2]	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses[1]	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota[1]	650	1,636	2,286	40
Debt Reacquisition Premiums[1]	254	960	1,214	177
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	442	542	65
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	75	--	75	12
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	309	--	309	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	--	1,985	1,985	24
North Dakota Renewable Resource Rider Accrued Revenues[2]	206	236	442	15
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	267	--	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	152	--	152	12
Total Regulatory Assets	$22,551	$129,576	$152,127	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$149,052	$149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	--	802	10
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
Other	5	84	89	192
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Minnesota Southwest Power Pool Transmission Cost Tracker Refund	--	609	609	22
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
Total Regulatory Liabilities	$9,688	$232,893	$242,581	
Net Regulatory Asset/(Liability) Position	$12,863	$(103,317)	$(90,454)	

[1]*Costs subject to recovery excluding a rate of return.*

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

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC 715 but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

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

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

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

The Unrecovered Tax Adjustment to Deferred Income Tax Asset results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes,* (ASC 740) and ASC 980.

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.

Table of Contents

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 168 months.

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.

Minnesota Renewable Resource Rider Accrued Revenues relate to an increase in renewable revenue requirements resulting from the expiration of tax credits for certain wind turbines. The balance represents amounts subject to recovery from Minnesota customers that have not been billed to Minnesota customers as of September 30, 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.

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

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

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

The Minnesota Southwest Power Pool Transmission Cost Recovery Tracker regulatory asset relates to costs incurred to serve Minnesota customers that are subject to recovery but that have not been billed to Minnesota customers as of September 30, 2018.

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

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

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

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

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

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

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

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

Table of Contents

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

The North Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the North Dakota share of OTP’s investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that are refundable to North Dakota customers as of September 30, 2018.

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

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

The Minnesota Southwest Power Pool Transmission Cost Tracker Refund relates to revenues billed for recovery of these transmission costs in excess of actual costs incurred that were subject to refund as of December 31, 2017.

The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

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

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

Reconciliation of Common Shareholders’ Equity

(in thousands)	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Equity
Balance, December 31, 2017	**$197,787**	**$343,450**	**$161,286**	**$ (5,631)**	**$696,892**
Common Stock Issuances, Net of Expenses	893	(986)			(93)
Common Stock Retirements	(356)	(2,656)			(3,012)
Net Income			68,184		68,184
Other Comprehensive Loss				(176)	(176)
Employee Stock Incentive Plans Expense		3,402			3,402
Common Dividends ($1.005 per share)			(39,895)		(39,895)
Balance, September 30, 2018	**$198,324**	**343,210**	**$189,575**	**$ (5,807)**	**$725,302**

Shelf Registrations and Common Share Distribution Agreement

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

Table of Contents

Common Shares

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

Common Shares Outstanding, December 31, 2017	39,557,491
Issuances:	
Executive Stock Performance Awards (2015 awards)	114,648
Executive Stock Performance Awards (2016 and 2017 awards)	18,600
Vesting of Restricted Stock Units	26,575
Restricted Stock Issued to Directors	18,200
Directors Deferred Compensation	578
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(71,208)
Common Shares Outstanding, September 30, 2018	39,664,884

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, 2018 and 2017. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company’s directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation:

	Three Months ended September 30		Nine Months ended September 30	
	2018	2017	2018	2017
Weighted Average Common Shares Outstanding – Basic	39,621,524	39,507,581	39,592,705	39,440,416
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	206,268	211,996	210,691	195,869
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	58,680	55,975	58,475	54,645
Nonvested Restricted Shares	14,761	16,982	17,712	18,923
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	2,332	2,832	2,522	3,009
Total Dilutive Shares	282,041	287,785	289,400	272,446

Weighted Average Common Shares Outstanding – Diluted	39,903,565	39,795,366	39,882,105	39,712,862

The effect of dilutive shares on earnings per share for the three- and nine-month periods ended September 30, 2018 and 2017, resulted in no differences greater than $0.0125 between basic and diluted earnings per share in total or from continuing or discontinued operations in any of the periods.

Table of Contents

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, 2018:

Award	Grant-Date	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Stock Performance Awards Granted to Executive Officers	February 5, 2018	54,000	$ 35.73	December 31, 2020
Restricted Stock Units Granted to Executive Officers	February 5, 2018	15,200	$ 41.325	25% per year through February 6, 2022
Restricted Stock Units Granted to Key Employees	April 9, 2018	12,945	$ 38.45	100% on April 8, 2022
Restricted Stock Units Granted to Key Employee	June 20, 2018	1,000	$ 42.46	100% on April 8, 2022
Restricted Stock Units Granted to Key Employee	September 25, 2018	835	$ 43.25	100% on April 8, 2022
Restricted Stock Granted to Nonemployee Directors	April 9, 2018	18,200	$ 43.40	33% per year through April 8, 2021

Under the performance share awards the aggregate award for performance at target is 54,000 shares. For target performance the participants would earn an aggregate of 27,000 common shares for achieving the target set for the Company’s 3-year average adjusted ROE. The participants would also earn an aggregate of 27,000 common shares based on the Company’s total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2018 through December 31, 2020, with the beginning and ending share values based on the average closing price of a share of the Company’s common stock for the 20 trading days immediately following January 1, 2018 and the average closing price for the 20 trading days immediately preceding January 1, 2021. Actual payment may range from zero to 150% of the target amount, or up to 81,000 common shares. There are no voting or dividend rights related to these awards until the shares, if any, are issued at the end of the performance measurement period. The amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to an officer who is party to an Executive Employment Agreement with the Company is to be made at target at the date of any such event. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 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.

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

The restricted shares granted to the Company's nonemployee directors are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreements. The grant-date fair value of each restricted share was the average of the high and low market price of one share of the Company's common stock on the date of grant.

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

Table of Contents

As of September 30, 2018, the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $5.3 million (before income taxes) which will be amortized over a weighted-average period of 2.0 years.

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(in thousands)	2018	2017	2018	2017
Stock Performance Awards Granted to Executive Officers	$718	$494	$2,037	$1,568
Restricted Stock Units Granted to Executive Officers	174	104	596	472
Restricted Stock Granted to Executive Officers	--	16	16	54
Restricted Stock Granted to Nonemployee Directors	165	144	496	416
Restricted Stock Units Granted to Key Employees	92	87	257	255
Totals	$1,149	$845	$3,402	$2,765

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, 2018, the Company was in compliance with these financial covenants.

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

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 47.9% and 58.5% based on OTP's 2018 capital structure petition effective by order of the MPUC on October 18, 2018. As of September 30, 2018, OTP's equity-to-total-capitalization ratio including short-term debt was 53.6% and its net assets restricted from distribution totaled approximately $469,000,000. Total capitalization for OTP cannot currently exceed $1,204,416,000.

8. Commitments and Contingencies

Construction and Other Purchase Commitments

At September 30, 2018 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019 of approximately $26.2 million. At December 31, 2017 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019 of approximately $41.0 million. At September 30, 2018 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $5.6 million. At December 31, 2017 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $6.7 million.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2041. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Coyote Station expire at the end of 2040. OTP's current coal purchase agreements for Big Stone Plant expire at the end of 2020. OTP entered into a coal purchase agreement with Peabody COALSALES, LLC effective May 14, 2018 for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2020. OTP has no fixed minimum purchase requirements under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement, except for the purchase of a portion of Big Stone Plant's coal requirements contracted to be purchased in 2018 and 2019 under existing agreements with Contura Coal Sales, LLC. OTP has an all-requirements agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. OTP has no fixed minimum purchase requirements under this agreement.

Table of Contents

Operating Leases

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

Contingencies

OTP had a \$1.6 million refund liability on its balance sheet as of September 30, 2018 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate. As discussed in Note 3 in greater detail, OTP believes its estimated accrued refund liability is appropriate based on the current set of facts and circumstances and is awaiting further action by 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 ROE refund described earlier, the most significant contingencies impacting the Company's consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed the established reserve amounts and litigation matters. Should all of these known items, excluding the ROE refund liability already recognized, result in liabilities being incurred, the loss could be as high as \$1.0 million.

In 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 CO2 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, EPA issued a Notice of Proposed Rulemaking to repeal the Clean Power Plan; comments were due in April 2018.

On August 21, 2018 EPA proposed a replacement for the Clean Power Plan -- the Affordable Clean Energy (ACE) Rule. Among other things, the ACE Rule (1) determines that the Best System of Emission Reduction for greenhouse gas emissions from coal-fired power plants is to improve the plants' heat rates, (2) identifies a list of "candidate technologies" for improving a plant's heat rate and (3) proposes that physical or operational changes to a power plant would not be a "major modification" triggering extensive New Source Review, if the change does increase hourly emissions. Comments on the ACE Rule are due October 31, 2018. If the ACE Rule goes into effect, states will have three years after the final rule to submit a state implementation plan.

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, 2018 will not be material.

9. Short-Term and Long-Term Borrowings

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

(in thousands)	Line Limit	In Use on September 30, 2018	Restricted due to Outstanding Letters of Credit	Available on September 30, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	$130,000	$ 15,489	$ --	$114,511	$130,000
OTP Credit Agreement	170,000	--	300	169,700	57,329
Total	$300,000	$ 15,489	$ 300	$284,211	$187,329

On October 31, 2018 both credit agreements were amended to extend the expiration dates by one year from October 31, 2022 to October 31, 2023.

Debt Issuances

2018 Note Purchase Agreement

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

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

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

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, 2018 and December 31, 2017:

September 30, 2018 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$ 15,489	$ 15,489
Long-Term Debt:			
3.55% Guaranteed Senior Notes, due December 15, 2026		$ 80,000	$ 80,000
Senior Unsecured Notes 4.63%, due December 1, 2021	$140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
Senior Unsecured Notes 4.07%, Series 2018A, due February 7, 2048	100,000		100,000
North Dakota Development Note, 3.95%, fully repaid April 1, 2018		--	--
PACE Note, 2.54%, due March 18, 2021		564	564
Total	$512,000	$ 80,564	$ 592,564
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	169	169
Unamortized Long-Term Debt Issuance Costs	1,991	420	2,411
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$510,009	$ 79,975	$ 589,984
Total Short-Term and Long-Term Debt (with current maturities)	$510,009	$ 95,633	$ 605,642

December 31, 2017 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$112,371	$ --	$ 112,371
Long-Term Debt:			
Term Loan, LIBOR plus 0.90%, due February 5, 2018		$ --	$ --
3.55% Guaranteed Senior Notes, due December 15, 2026		80,000	80,000
Senior Unsecured Notes 4.63%, due December 1, 2021	$140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018		27	27
PACE Note, 2.54%, due March 18, 2021		684	684
Total	$412,000	$ 80,711	$ 492,711
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	186	186

Unamortized Long-Term Debt Issuance Costs	1,684	461	2,145
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$410,316	$ 80,064	$ 490,380
Total Short-Term and Long-Term Debt (with current maturities)	$522,687	$ 80,250	$ 602,937

Table of Contents

10. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(in thousands)	2018	2017	2018	2017
Service Cost—Benefit Earned During the Period	$1,615	$1,407	$4,845	$4,221
Interest Cost on Projected Benefit Obligation	3,363	3,534	10,089	10,604
Expected Return on Assets	(5,300)	(4,807)	(15,899)	(14,421)
Amortization of Prior-Service Cost:				
From Regulatory Asset	4	30	12	89
From Other Comprehensive Income[1]	--	1	--	3
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,784	1,273	5,351	3,818
From Other Comprehensive Income[1]	46	31	137	94
Net Periodic Pension Cost[2]	$1,512	$1,469	$4,535	$4,408
[1]*Corporate cost included in nonservice cost components of postretirement benefits.*				
[2]*Allocation of Costs:*				
Costs included in OTP capital expenditures	*$455*	*$285*	*$1,162*	*$856*
Service costs included in electric operation and maintenance expenses	*1,119*	*1,100*	*3,561*	*3,300*
Service costs included in other nonelectric expenses	*41*	*33*	*121*	*101*
Nonservice costs capitalized as regulatory assets	*(29)*	*--*	*(74)*	*--*
Nonservice costs included in nonservice cost components of postretirement benefits	*(74)*	*51*	*(235)*	*151*

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

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

(in thousands)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Service Cost—Benefit Earned During the Period	$100	$73	$300	$218
Interest Cost on Projected Benefit Obligation	399	421	1,197	1,264
Amortization of Prior-Service Cost:				
From Regulatory Asset	4	4	12	12
From Other Comprehensive Income[1]	10	10	29	29
Amortization of Net Actuarial Loss:				
From Regulatory Asset	66	70	200	213
From Other Comprehensive Income[1]	166	110	496	330
Net Periodic Pension Cost[2]	$745	$688	$2,234	$2,066
[1]Amortization of prior service costs and net actuarial losses from other comprehensive income are included in nonservice cost components of postretirement benefits on the face of the Company's consolidated statements of income.				
[2]Allocation of Costs:				
Service costs included in electric operation and maintenance expenses	*$24*	*$24*	*$74*	*$71*
Service costs included in other nonelectric expenses	*76*	*49*	*226*	*147*
Nonservice costs included in nonservice cost components of postretirement benefits	*645*	*615*	*1,934*	*1,848*

32

Table of Contents

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(in thousands)	2018	2017	2018	2017
Service Cost—Benefit Earned During the Period	$382	$357	$1,145	$1,069
Interest Cost on Projected Benefit Obligation	646	678	1,937	2,034
Amortization of Net Actuarial Loss:				
From Regulatory Asset	412	233	1,236	699
From Other Comprehensive Income[1]	11	5	32	17
Net Periodic Postretirement Benefit Cost[2]	$1,451	$1,273	$4,350	$3,819
Effect of Medicare Part D Subsidy	$(37)	$(141)	$(110)	$(421)
[1]Corporate cost included in nonservice cost components of postretirement benefits.				
[2]Allocation of Costs:				
Costs included in OTP capital expenditures	*$108*	*$247*	*$275*	*$742*
Service costs included in electric operation and maintenance expenses	*264*	*278*	*841*	*835*
Service costs included in other nonelectric expenses	*10*	*9*	*29*	*26*
Nonservice costs capitalized as regulatory assets	*301*	*--*	*769*	*--*
Nonservice costs included in nonservice cost components of postretirement benefits	*768*	*739*	*2,436*	*2,216*

11. Fair Value of Financial Instruments

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

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

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of September 30, 2018 and December 31, 2017 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.50% and LIBOR plus 1.25%, respectively, which approximate market rates.

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

	September 30, 2018		December 31, 2017	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$649	$649	$16,216	$16,216
Short-Term Debt	(15,489)	(15,489)	(112,371)	(112,371)
Long-Term Debt including Current Maturities	(590,153)	(589,368)	(490,566)	(543,691)

Table of Contents

13. Income Tax Expense – Continuing Operations

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2018	2017	2018	2017
Income Before Income Taxes – Continuing Operations	$30,632	$24,808	$82,391	$73,314
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26% for 2018, 39% for 2017)	$7,964	$9,675	$21,422	$28,592
Increases (Decreases) in Tax from:				
Federal Production Tax Credits	(707)	(1,349)	(2,757)	(5,411)
Property Related Differences and Other Regulatory Adjustments	1,187	103	(911)	243
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(212)	(774)	(637)
Excess Tax Deduction – Equity Method Stock Awards	(73)	--	(698)	(697)
Research and Development and Other Tax Credits	(227)	(189)	(636)	(576)
Other Comprehensive Income Deferred Tax Rate Adjustment	--	--	(531)	--
Allowance for Funds Used During Construction – Equity	(138)	(92)	(416)	(250)
Corporate-Owned Life Insurance	(332)	(118)	(360)	(620)
Employee Stock Ownership Plan Dividend Deduction	(99)	(172)	(298)	(517)
Section 199 Domestic Production Activities Deduction	--	(330)	--	(990)
Other Items – Net	42	(281)	166	158
Income Tax Expense – Continuing Operations	$7,359	$7,035	$14,207	$19,295
Effective Income Tax Rate – Continuing Operations	24.0 %	28.4 %	17.2 %	26.3 %

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

(in thousands)	2018	2017
Balance on January 1	$684	$891
Increases (Decreases) Related to Tax Positions for Prior Years	6	28
Increases Related to Tax Positions for Current Year	113	220
Uncertain Positions Resolved During Year	(186)	(206)
Balance on September 30	$617	$933

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

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of September 30, 2018, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2015 for federal and North Dakota income taxes and prior to 2014 for Minnesota state income taxes.

The Company recognized the income tax effects of the TCJA in its 2017 consolidated financial statements in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC Topic 740, *Income Taxes*, and allowed up to one year to complete the required analyses and accounting for the TCJA. At December 31, 2017 the Company was able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, changes to bonus depreciation and consequences on the Company's regulatory liabilities. The accounting for the income tax effects of the enactment of the TCJA is complete as of September 30, 2018. The Company did not make any material adjustments to the amounts recorded at December 31, 2017 in 2018.

Table of Contents

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

Results of Operations

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

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

Consolidated operating revenues were $227.7 million for the three months ended September 30, 2018 compared with $216.5 million for the three months ended September 30, 2017. Operating income was $38.3 million for the three months ended September 30, 2018 compared with $33.0 million for the three months ended September 30, 2017. The Company recorded diluted earnings per share of $0.58 for the three months ended September 30, 2018 compared with $0.45 for the three months ended September 30, 2017.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three-month periods ended September 30, 2018 and 2017 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	September 30, 2018	September 30, 2017
Operating Revenues:		
Electric	$10	$5
Costs of Products Sold	4	8
Other Nonelectric Expenses	6	(3)

Electric

Three Months Ended

	September 30,			%
(in thousands)	2018	2017	Change	Change
Retail Sales Revenues from Contracts with Customers	$88,750	$88,482	$268	0.3
Changes in Accrued Revenues under Alternative Revenue Programs	(317)	471	(788)	(167.3)
Total Retail Sales Revenue	$88,433	$88,953	$(520)	(0.6)
Wholesale Revenues – Company Generation	2,826	1,549	1,277	82.4
Other Revenues	14,183	12,897	1,286	10.0
Total Operating Revenues	$105,442	$103,399	$2,043	2.0
Production Fuel	17,129	16,096	1,033	6.4
Purchased Power – System Use	9,664	13,371	(3,707)	(27.7)
Other Operation and Maintenance Expenses	33,897	35,469	(1,572)	(4.4)
Depreciation and Amortization	14,023	13,157	866	6.6
Property Taxes	4,094	3,721	373	10.0
Operating Income	$26,635	$21,585	$5,050	23.4
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	1,079,622	1,060,858	18,764	1.8
Wholesale kwh Sales – Company Generation	93,790	57,400	36,390	63.4
Heating Degree Days	107	37	70	189.2
Cooling Degree Days	339	284	55	19.4

Table of Contents

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

	Three Months ended September 30,	
	2018	2017
Heating Degree Days	209.8 %	69.8 %
Cooling Degree Days	95.8 %	80.2 %

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 third quarters of 2018 and 2017 and between the quarters:

	2018 vs Normal	2017 vs Normal	2018 vs 2017
Effect on Diluted Earnings Per Share	$(0.00)	$(0.01)	$0.01

The $0.5 million decrease in retail revenue includes:

A $4.0 million increase in revenues mainly due to the additional amount of interim rate refund recorded in third quarter 2017 related to the Minnesota Public Utilities Commission’s (MPUC’s) final order in the 2016 general rate case.

A $1.4 million increase in revenues, net of an estimated refund, related to an interim rate increase implemented in January 2018 in conjunction with OTP's 2017 general rate increase request in North Dakota.

A $0.8 million increase in Minnesota Renewable Resource Adjustment (RRA) rider revenues related to an increase in renewable revenue requirements resulting from the expiration of production tax credits for certain wind turbines.

A $0.8 million increase in revenues related to increased electricity consumption due to warmer weather in third quarter 2018, evidenced by a 19.4% increase in cooling degree days between the periods.

offset by:

A $4.2 million decrease in revenues related to the recovery of lower fuel and purchased power costs incurred to serve retail customers, driven by more kwhs generated from low-fuel-cost, company-owned resources combined with a reduction in higher-cost power purchases.

A $2.3 million reduction in revenues due to a provision for refunds to Minnesota and South Dakota customers related to lower federal income taxes under the 2017 Tax Cuts and Jobs Act (TCJA).

A $0.6 million decrease in North Dakota and South Dakota Environmental Cost Recovery (ECR) rider revenues due to a reduction in the return on equity (ROE) component of the North Dakota rider from 10.75% in 2017 to 9.77% in 2018, less federal taxes being recovered through the riders and a lower investment balance of environmental upgrades due to depreciation.

A $0.4 million reduction in revenues related to a reduction in transmission costs, including lower federal income taxes under the TCJA, recoverable in rates and through transmission cost recovery (TCR) riders in North Dakota and Minnesota.

Wholesale electric revenues increased $1.3 million due to a 63.4% increase in wholesale kwh sales and an 11.7% increase in wholesale electric prices. Increased demand and higher wholesale prices combined with increased availability of OTP generating units provided greater opportunity for economic dispatch and wholesale energy sales in third quarter 2018 compared with third quarter 2017.

Other electric revenues increased $1.3 million due to increases in transmission tariff and transmission services revenue.

Production fuel costs increased $1.0 million, due to a 21.5% increase in kwhs generated from OTP’s fuel burning plants to provide electricity for the increases in retail and wholesale demand driven by warmer weather in OTP’s service territory in third quarter 2018 compared with third quarter 2017.

The cost of purchased power to serve retail customers decreased $3.7 million in relation to a 47.5% decrease in kwhs purchased due to higher market prices and increased availability of, and sourcing from, company-owned generating units.

Table of Contents

Electric operating and maintenance expenses decreased $1.6 million due to the establishment of a $2.7 million regulatory asset for deferred recovery of an income tax adjustment related to TCJA guidance issued in third quarter 2018. This decrease was partially offset by a $1.1 million increase in external service costs related to a scheduled eight-week maintenance outage at Big Stone Plant that began in September 2018. The income tax adjustment is the result of August 2018 Internal Revenue Service (IRS) guidance clarifying changes related to the treatment of bonus depreciation rules for 2017, affecting 2017 deductions and 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. In accordance with regulatory accounting treatment, OTP recorded a regulatory asset and offsetting credit to operating expense of $2.7 million. The regulatory asset will be amortized to expense as the related revenue is recovered in rates.

Property tax expense increased $0.4 million due to an increase in North Dakota property taxes in 2018.

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

Manufacturing

	Three Months Ended September 30,			%
(in thousands)	2018	2017	Change	Change
Operating Revenues	$67,027	$54,355	$12,672	23.3
Cost of Products Sold	51,143	41,638	9,505	22.8
Operating Expenses	7,842	6,161	1,681	27.3
Depreciation and Amortization	3,716	3,780	(64)	(1.7)
Operating Income	$4,326	$2,776	$1,550	55.8

The $12.7 million increase in revenues in our Manufacturing segment includes the following:

Revenues at BTD Manufacturing, Inc. (BTD) increased $11.8 million, including increases in parts revenue of $4.1 million to manufacturers of construction equipment, $2.2 million to manufacturers of agricultural equipment, $2.0 million to manufacturers of lawn and garden equipment, $1.7 million to manufacturers of industrial equipment and $1.1 million to manufacturers of recreational vehicles. Included in the parts revenue increases is the pass through of higher material costs of $4.2 million, with the remaining increase due to higher sales volume and a slight increase in pricing unrelated to material cost increases. Revenues from scrap metal sales increased $0.7 million due to higher scrap volume from increased production and a 6% increase in scrap metal pricing.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $0.9 million due to a $1.6 million increase in sales of horticultural containers, partially offset by decreases in sales of industrial and life sciences products totaling $0.7 million.

The $9.5 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased $8.7 million due to increased sales volume and the $4.2 million in higher material costs recovered in revenue.

Cost of products sold at T.O. Plastics increased $0.8 million due to the increase in sales volume and higher labor costs.

The $1.7 million increase in operating expenses in our Manufacturing segment includes a $1.6 million increase in expenses at BTD resulting from increases in in labor, benefit and recruiting costs for additional employees.

Table of Contents

Plastics

(in thousands)	Three Months Ended September 30, 2018	2017	Change	% Change
Operating Revenues	$55,203	$58,708	$(3,505)	(6.0)
Cost of Products Sold	42,222	44,600	(2,378)	(5.3)
Operating Expenses	3,260	3,083	177	5.7
Depreciation and Amortization	907	976	(69)	(7.1)
Operating Income	$8,814	$10,049	$(1,235)	(12.3)

Plastics segment revenues decreased $3.5 million due to a 12.5% decrease in pounds of polyvinyl-chloride (PVC) pipe sold, partially offset by a 7.5% increase in PVC pipe prices. Higher sales volume in third quarter 2017 was mainly due to increased sales and pricing resulting from hurricanes in the Gulf Coast region of the United States, where the major U.S. resin production plants are located. Hurricane Harvey had a significant impact on market conditions for September 2017. Major resin suppliers shut down production facilities which impacted raw material availability. This created pipe-availability concerns among distributors and contractors, which accelerated pipe demand and created positive sales-price pressure in the market, impacting our third quarter 2017 diluted earnings by an estimated $0.04 per share.

Cost of products sold decreased $2.4 million due to the 12.5% decrease in sales volume, partially offset by an 8.2% increase in the cost per pound of pipe sold. Although sales volume decreased while the cost per pound of pipe sold increased, gross margin per pound of PVC pipe sold still improved by 5.2% as a result of the 7.5% increase in revenue per pound of PVC pipe sold. Plastics segment operating expenses increased by $0.2 million.

Corporate

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

(in thousands)	Three Months Ended September 30, 2018	2017	Change	% Change
Operating Expenses	$1,451	$1,384	$ 67	4.8

Depreciation and Amortization	62	14	48	342.9

Other Income

The $0.7 million increase in other income in the three months ended September 30, 2018 compared with the three months ended September 30, 2017 includes $0.3 million of nontaxable life insurance benefits from corporate-owned life insurance and a $0.3 million increase in other income at OTP related to an increase in allowance for equity funds used during construction (AFUDC) resulting from an increase in construction work in progress subject to AFUDC.

Table of Contents

Income Taxes – Continuing Operations

Income tax expense - continuing operations increased only $0.3 million in the three months ended September 30, 2018 compared with the three months ended September 30, 2017, despite a $5.8 million increase in income before income taxes, mainly due to the reduction in the federal income tax rate from 35% to 21% under the TCJA decreasing income taxes by approximately $2.0 million. The $2.0 million tax decrease due to the lower tax rate was offset by a $2.0 million increase due to the reversal of excess deferred taxes related to IRS guidance clarifying changes to bonus depreciation under the TCJA applied to 2017 income taxes at OTP. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three-month periods ended September 30, 2018 and 2017:

	Three Months Ended September 30,	
(in thousands)	2018	2017
Income Before Income Taxes – Continuing Operations	$30,632	$24,808
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26% for 2018, 39% for 2017)	$7,964	$9,675
Increases (Decreases) in Tax from:		
Property Related Differences and Other Regulatory Adjustments	1,187	103
Federal Production Tax Credits (PTCs)	(707)	(1,349)
Corporate-Owned Life Insurance	(332)	(118)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(212)
Research and Development and Other Tax Credits	(227)	(189)
Allowance for Funds Used During Construction – Equity	(138)	(92)
Employee Stock Ownership Plan Dividend Deduction	(99)	(172)
Excess Tax Deduction – Equity Method Stock Awards	(73)	--
Section 199 Domestic Production Activities Deduction	--	(330)
Other Items – Net	42	(281)
Income Tax Expense – Continuing Operations	$7,359	$7,035
Effective Income Tax Rate – Continuing Operations	24.0 %	28.4 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs decreased 46.9% in the three months ended September 30, 2018 compared with the three months ended September 30, 2017 due to the PTC eligibility period ending for one of OTP's wind farms. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Comparison of the Nine Months Ended September 30, 2018 and 2017

Consolidated operating revenues were $695.3 million for the nine months ended September 30, 2018 compared with $642.7 million for the nine months ended September 30, 2017. Operating income was $106.0 million for the nine months ended September 30, 2018 compared with $98.2 million for the nine months ended September 30, 2017. The Company recorded diluted earnings per share of $1.71 for the nine months ended September 30, 2018 compared with $1.36 for the nine months ended September 30, 2017.

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, 2018 and 2017 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	September 30, 2018	September 30, 2017